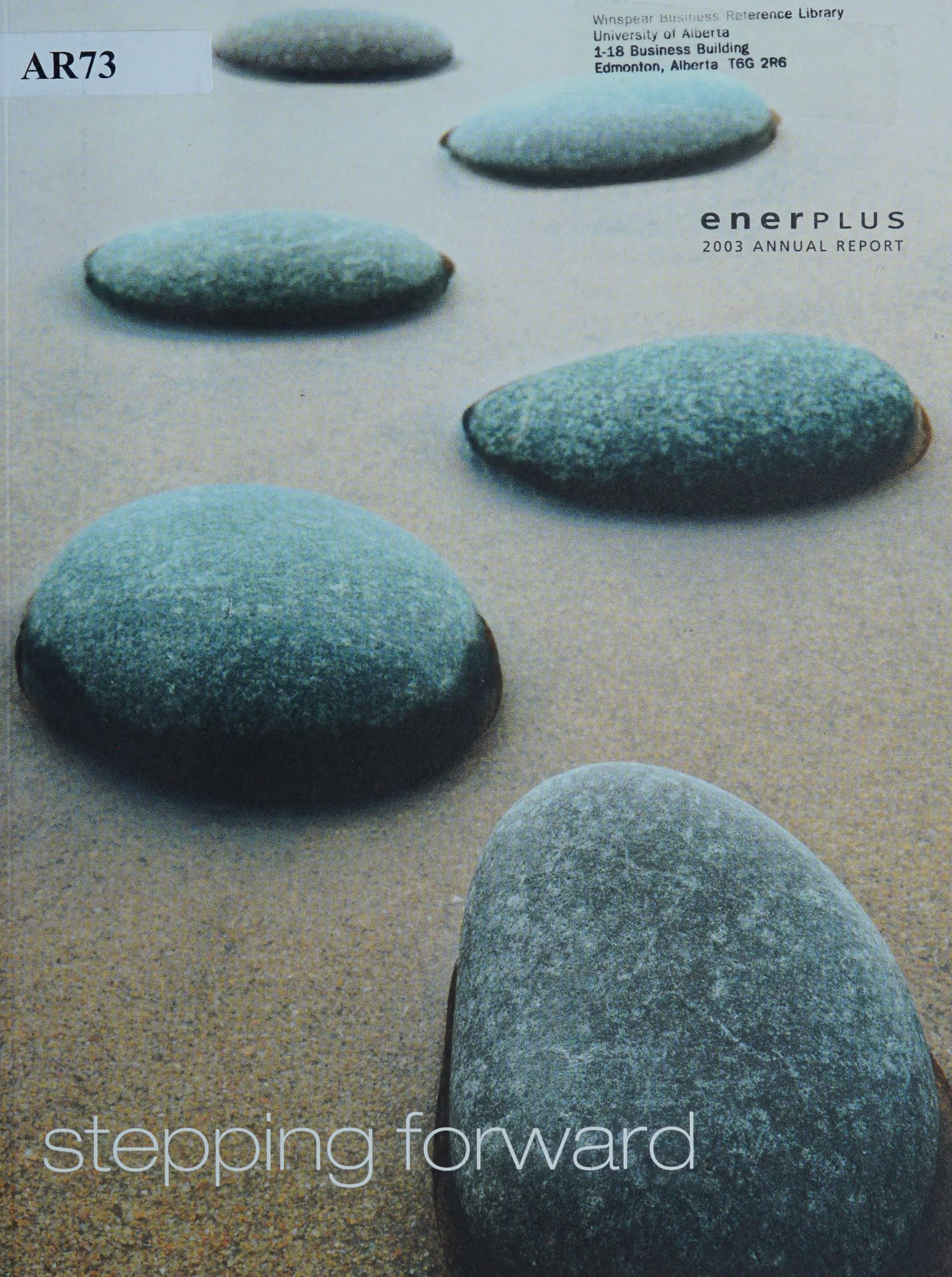
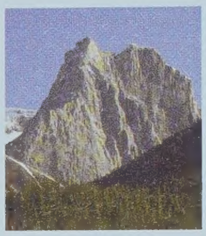
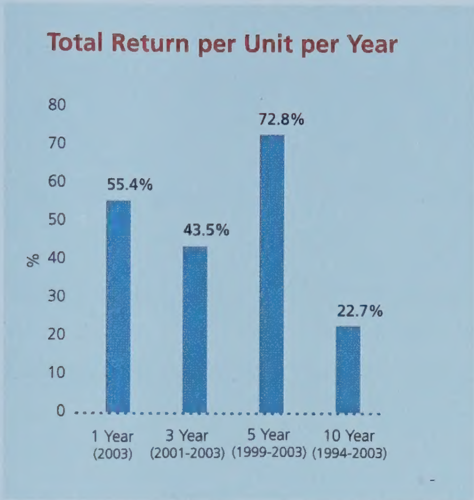


enerPLUS
2003 ANNUAL REPORT

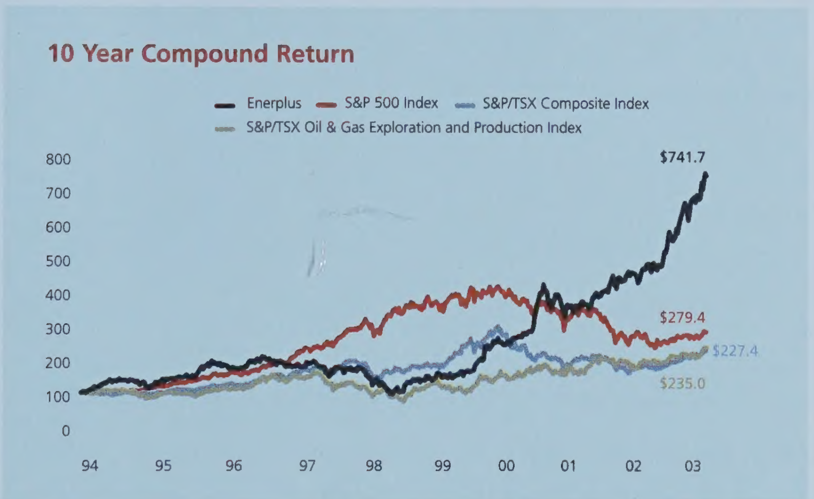
stepping forward



Created in 1986, Enerplus is Canada's oldest and largest conventional oil and gas income fund with a diverse asset base located in western Canada. Enerplus offers investors the benefits of owning a large portfolio of income generating energy assets without the exploration risks commonly associated with traditional exploration and production companies. As an experienced acquirer and operator, Enerplus invests in mature producing properties with predictable production profiles, long reserve lives and high cash netbacks. Our growth has been achieved through accretive acquisitions and the low-risk development of our asset base. The cash flow from these properties is distributed to unitholders on a monthly basis, providing them with a lower risk investment within the energy sector that has consistently outperformed the S&P/TSX Oil and Gas Exploration and Production Index over both the short and long-term. Stepping forward, we recognize the need to expand our opportunity set within the energy industry to provide future growth potential for the Fund and sustain distributions over the long-term.



Enerplus has consistently provided above-average returns to our unitholders in both the short and long-term.



On a 10-year basis, Enerplus has clearly outperformed the benchmark indices by a factor of 3 times.

proven performance

Selected Financial and Operating Results

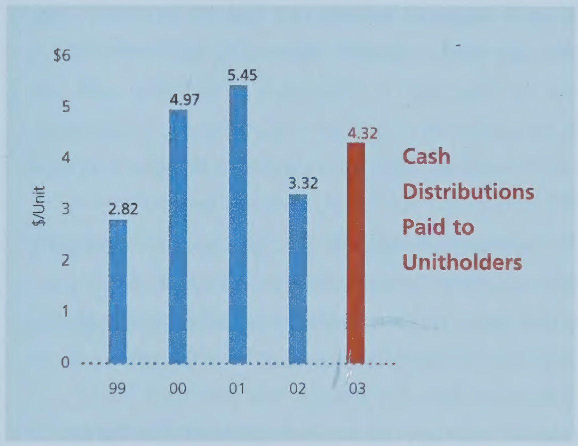
For the twelve months ended December 31,	2003	2002
Financial per Unit		
Net Income	$ 2.90	$ 1.61
Funds Flow from Operations (prior to Management Internalization)[1]	5.43	4.03
Internalization of Management Contract	(0.64)	–
Funds Flow from Operations [1]	4.79	4.03
Cash Distributed [2]	4.32	3.32
Cash Withheld for Debt Repayment	0.39	0.62
Payout Ratio	92%	84%
Payout Ratio (prior to Management Internalization)[1]	81%	84%
Net Debt/Trailing 12 Month Funds Flow Ratio[1]	0.6x	1.2x
Market Capitalization ($ millions)	$ 3,713	$ 2,325
Long-Term Debt net of cash ($ millions)	258	361
Enterprise Value ($ millions)	$ 3,971	$ 2,686
Average daily trading volume	446,128	272,983
Average Daily Production		
Natural gas (Mcf/day)	240,907	210,517
Crude oil (bbls/day)	24,597	23,288
NGLs (bbls/day)	4,666	4,410
Total (BOE/day) (6:1)	69,414	62,784
% Natural gas	58%	56%
Average Selling Price Pre-Hedging		
Natural gas (per Mcf)	$ 6.30	$ 3.87
Crude oil (per bbl)	36.15	34.37
NGLs (per bbl)	33.43	25.68
US$ exchange rate	$ 0.716	$0.637
Reserves		
Proved plus Probable Reserves (MMBOE)	328.1	330.4[3]
Proved plus Probable Reserve Life Index (years)	13.3	13.8[3]
Netback per BOE		
Oil & Gas Sales Before Hedging	$ 36.94	$ 27.49
Cost of Hedging	(1.81)	(0.38)
Royalties, net of ARTC	(7.51)	(5.75)
Operating Costs	(6.73)	(5.86)
Operating Netback	20.89	15.50
General and Administrative, net of unit based compensation	(0.95)	(0.70)
Management Fees	(0.12)	(0.94)
Interest and foreign exchange, net of non cash expense	(0.82)	(0.78)
Taxes	(0.26)	(0.23)
Restoration and abandonment	(0.26)	(0.20)
Funds Flow from Operations (prior to Management Internalization) [1]	18.48	12.65
Internalization of Management Contract	(2.17)	–
Funds Flow from Operations [1]	$ 16.31	$ 12.65

[1] See discussion in Management's Discussion and Analysis
[2] Calculated based on distributions paid or payable each month relating to the period
[3] Based on established reserves (proved plus 50% probable)

President's Message

Gordon J. Kerr
President & Chief Executive Officer

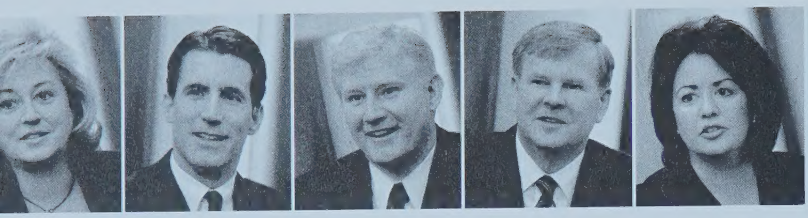
Enerplus had another highly successful year in 2003. For the second year in a row, we ranked first in our peer group on a three-year average total return. We accomplished many of our goals and, in fact, exceeded our production target. I am proud to report the following summary of our 2003 successes:



HIGHLIGHTS:

- 55.4% total return for our unitholders;
- Increased distributions by 30% to $4.32 per unit;
- Achieved a record level of production of 69,414 BOE per day even after successfully selling $73.2 million of non-core properties;
- Drilled 294 net wells with a 98% success rate;
- Acquired 28.1 MMBOE of reserves at a cost of $8.02 per BOE;
- Maintained one of the longest reserve life indices in the sector at 13.3 years on a proved plus probable basis under the new NI 51-101 guidance;
- Completed the internalization of the management contract for an all-in cost of $55.1 million, or less than two times the management fees that would otherwise have been paid in 2003;
- Placed US$54 million of debt with a 10-year average term at a rate of 5.46%;
- Achieved a top quartile, three-year average FD&A cost of $8.54 per BOE, inclusive of future development costs.

In 2003, we spent $157.7 million on our drilling and facility enhancement activities. We continued to capitalize on our expertise and opportunities in the areas of shallow natural gas development and waterflood optimization. We added 2,150 BOE per day of shallow gas production and approximately 2,000 BOE per day from our oil waterflood projects, net to Enerplus, based on initial production rates. We were also successful in bringing on over 2,400 BOE per day of production in the Foothills area of the Western Canadian Sedimentary Basin ("WCSB"). Through our joint venture relationships, we have gained access to a broader spectrum of technical skills and opportunities that have enhanced our success in the Foothills area.



FROM LEFT TO RIGHT
Heather J. Culbert Senior Vice President, Corporate Services
Garry A.Tanner Senior Vice President & Chief Operating Officer
Eric P. Tremblay Senior Vice President, Capital Markets
Robert J. Waters Senior Vice President & Chief Financial Officer
Jo-Anne M. Caza Vice President, Investor Relations

In addition to our development activities, we spent $225.3 million in 2003 on acquisitions, adding to core properties, most notably for our acquisitions of PCC Energy Inc. and PCC Energy Corp. (collectively "PCC"). The acquisition of PCC increased our portfolio of natural gas properties including an interest in the 300 MMcf/day Hanlan Robb gas plant. Our total acquisitions together with our reserve revisions represented a replacement of 99% of our 2003 production at a cost of $11.60 per BOE on a proved plus probable basis. We also sold $73.2 million of non-core properties, further improving our portfolio of oil and natural gas assets.

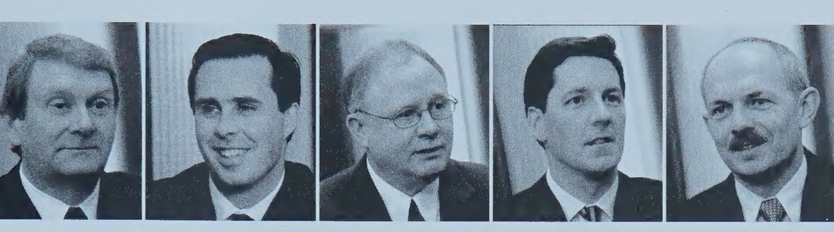
In evaluating our 2003 reserves, our independent evaluators have applied the new more stringent criteria contained within National Instrument 51-101 ("NI 51-101"). The newly defined proved plus probable ("P+P") categorization for oil and gas reserves equates reasonably to the previously referenced established reserves. Proved reserves, however, were evaluated on a more conservative basis and subsequently have been reduced. I am pleased to advise that we have been able to essentially maintain our level of P+P reserves when comparing to our prior year's established reserve number. Equally important to note is that we have maintained a strong proved reserve life index ("RLI") of 10.1 years and a proved plus probable RLI of 13.3 years. It is this reserve base and associated production profile that provides the underpinning to our ongoing distributions.

STEPPING FORWARD

Throughout 2003 and continuing into 2004, the acquisition market for oil and natural gas assets has become increasingly competitive. We are in competition with a growing number of trusts and emerging junior oil and gas companies. To mitigate this competition, our focus will be on larger sized acquisitions where we have a view to adding meaningful value to our asset base. We believe our investment strategies combined with our deal strength and disciplined portfolio approach will continue to result in successful acquisitions over the long term.

In January 2004, we completed the acquisition of Ice Energy Limited ("Ice Energy"), a junior oil and gas company focused on shallow gas exploration and development. This acquisition gives us a significant position in the developing shallow natural gas area of Shackleton, Saskatchewan. With Ice Energy, we have added approximately 2,300 BOE per day of production, 95% of which is natural gas, beginning in 2004. We have also identified approximately 250 drilling locations that we expect will increase our net production to 3,000 BOE per day in 2005.

In making the Ice Energy acquisition, we benefited from an initial equity investment in the company that improved our understanding of the assets, our assessment of their economic potential and our overall acquisition cost. We intend to continue our strategy of making highly selective equity investments in



FROM LEFT TO RIGHT
Daryl W. Cook Vice President, Operations
Ian C. Dundas Vice President & Director, Business Development
Wayne T. Foch Vice President, Finance
David A. McCoy General Counsel & Corporate Secretary
Daniel M. Stevens Vice President, Development Services

junior oil and gas exploration companies. This will enhance our ability to make acquisitions and further our technical knowledge on developing areas.

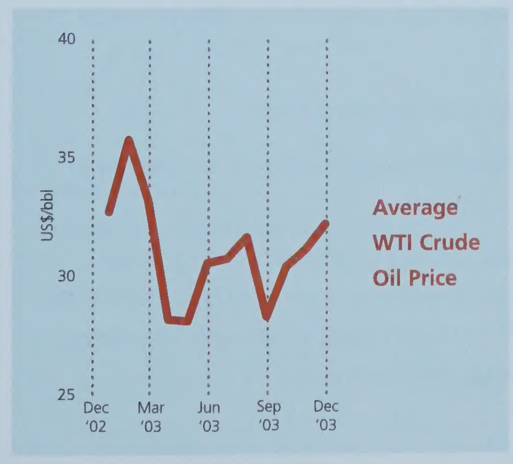
Over the last few years, there has been increasing recognition of the potential for exploitation of natural gas from coal ("NGC") in western Canada. We have been and will continue to test for NGC potential on a number of our properties. Through our recent acquisition of Ice Energy, we are also participating in our first commercial scale NGC project with an experienced NGC producer. We will pursue this opportunity diligently but recognize that it takes patience, persistence and knowledge to properly realize the value from this resource.

Progress is also continuing on the development of the Joslyn Creek lease (Oil Sands Lease # 24) in which we hold a 16% working interest. Currently, a steam assisted gravity drainage ("SAGD") pilot project is underway on this lease with initial production expected in the second quarter of 2004. We expect to record reserves for this investment in 2004.

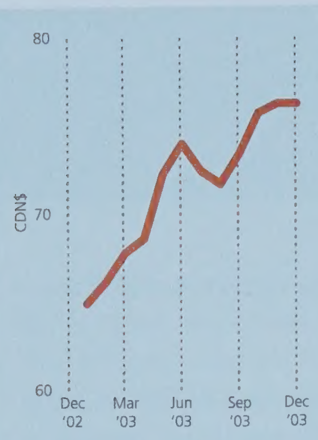
COMMODITY PRICES

Over the course of 2003, the increase in oil prices outpaced analysts' forecasts. The West Texas Intermediate ("WTI") crude oil reference price averaged US$31.04 per barrel for the year, representing a year-over-year increase of 19%. A number of factors influenced oil prices not the least of which were disruptions of supply, the decline of the US dollar against other currencies and an increase in demand, most notably out of China.

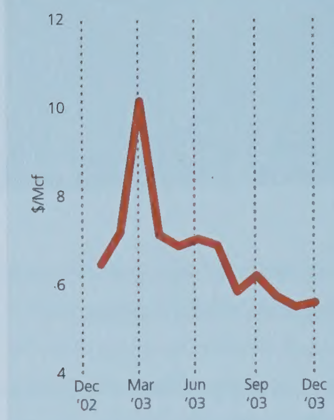
Countering this increase in the US dollar reference price was the rapid strengthening of the Canadian dollar. On an equivalent Canadian dollar basis, WTI increased only a modest 6%. The general consensus of price forecasters now seems to be that oil prices will continue at levels higher than the long-term historical averages.



Natural gas prices also remained strong throughout the year with NYMEX averaging US$5.54 per Mcf and the AECO reference price averaging CDN$6.70 per Mcf. Initial concerns over lower levels of natural gas in storage going into the heating season provided support for natural gas prices. However, as we have come through the heating season, the levels of natural gas



Average CDN$/US$ Exchange Rate



Average AECO Natural Gas Price

in storage have returned to be in line with historical averages. Nevertheless, natural gas prices continue to be supported by concerns over declining supply and increasing demand resulting from a recovering U.S. economy.

In view of the potential for continued price volatility in both commodities, we plan to continue our price risk management program. We will be looking to increase the price levels of downside protection while retaining exposure to upside commodity price movement. We believe this will improve the stability of distributions to our unitholders and help protect the economics around our acquisition and development activities over the long run.

2004 OUTLOOK

As we move into 2004, the oil and gas industry in western Canada continues to benefit from robust cash flows. We also face a number of challenges emanating out of a maturing basin and high activity levels. These include smaller pool sizes for new discoveries and associated higher finding and development costs, increasing operating costs and a shortage of skilled labour.

We continue to develop our business processes and skill sets to improve our competitive advantage to meet these challenges:

- We are conducting integrated field and operating cost reviews on our properties to improve our oil and natural gas recoveries and cost efficiencies;
- We have hired additional skilled staff to improve on our pool depletion plans; and
- We have more closely aligned our support services with our business units to improve the execution of our business plans.

Our business model, combined with our size, skills and processes, affords us an opportunity to take advantage of the challenges being faced. We expect to continue to grow our asset base of conventional oil and gas assets within the WCSB. At the same time, we will continue to look to broaden our energy asset base and be creative in our approach to developing business relationships.

In 2004, we plan to spend approximately $170 million on the further development of our asset base. This will include investing $38 million on shallow gas development, $27 million on crude oil waterflood development and up to $20 million on joint venture opportunities. Production volumes in 2004 are expected to be slightly lower than our 2003 annual average production at 68,300 BOE/day. However, this does not reflect any further acquisitions, other than Ice Energy, or divestments that we may make in 2004.

Based upon industry trends and activity levels, we are expecting an increase in operating and administrative costs compared to 2003. Our balance sheet remains strong and we expect to continue to make distributions to unitholders in the 75% to 90% range of our available funds flow. I recommend readers review our guidance provided for 2004 within the "Management's Discussion and Analysis" section of this annual report for a more fulsome discussion on these and other relevant points.

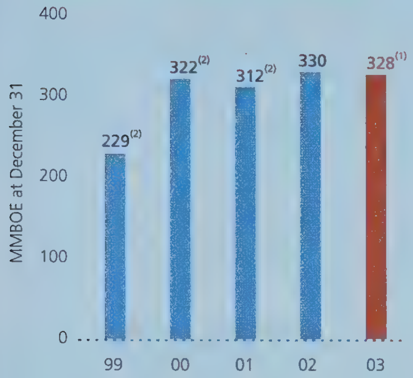
Over the past few years, there has been an increasing level of scrutiny placed on organizations with respect to corporate governance. I thank all the members of our Board of Directors for their diligence and the demands on their time in ensuring that we continue to maintain a strong corporate governance structure and culture. Again, I encourage our readers to review our discussion on "Corporate Governance" in this annual report to assure themselves they can place confidence in these structures, management and our Board of Directors.

Finally, I thank all the members of our team at Enerplus. In addition to our success in 2003, I am very proud of the fact that we are able to report to our stakeholders that we operate at the highest level (Platinum) under the Canadian Association of Petroleum Producers ("CAPP") Stewardship program. We have had zero lost time employee injuries in the conduct of our operations again this past year. I am also proud of the energy, resources and time our people have given to improve the quality of life in the communities where we live and operate.

Our focus has been and will continue to be on maximizing value for all of our stakeholders over the long-term. We thank you for investing in Enerplus and look forward to our continued success.

Gordon J. Kerr
President & Chief Executive Officer

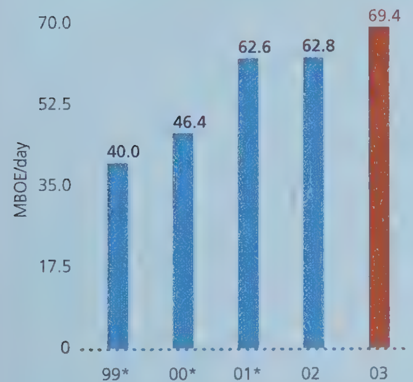
Proved & Probable Reserves



(1) 2003 only – prior years reflect established reserves
(2) Enerplus and EnerMark reserves combined

Enerplus replaced 99% of its reserves in 2003

Annual Average Production



* Enerplus and EnerMark production combined

Production volumes increased for the 5th consecutive year.

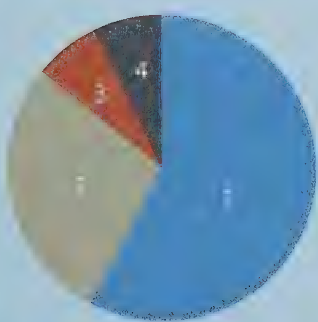
superior assets

Diversified by Property and Commodity

As Canada's largest conventional oil and gas income fund, Enerplus is focused in western Canada with a diverse set of assets producing both oil and natural gas. During 2003, we produced in excess of 69,400 BOE/day and invested over $150 million of development capital. Employing a complement of technical, operating and administrative staff, Enerplus has proven itself as an effective and efficient operator and developer over the last 18 years.

Enerplus is focused on value creation activities with specific expertise in shallow natural gas, crude oil waterfloods and foothills development through our joint venture partnerships. Overall, we brought on 11,000 BOE/day for an average on-stream cost of $14,336 per daily barrel in 2003 with a majority of this capital invested in our core areas. We have the advantage of a large and diversified asset base that mitigates risk and supports more stable cash distributions. With interests in approximately 4,000 net operated wells and 1,200 net partner-operated wells, we have a window into activity throughout the basin that allows us to participate in attractive emerging areas and provides a wider spectrum of acquisition opportunities.

ENERPLUS ENJOYS A BALANCED PRODUCTION MIX THAT HELPS TO MITIGATE THE PRICE RISK OF ANY ONE COMMODITY



2003 Production Mix

1 Natural Gas 58%
2 Light & Medium Crude Oil 28%
3 Heavy Crude Oil 7%
4 Natural Gas Liquids 7%

Our asset base contains a healthy mix of operated and non-operated properties, producing a combination of natural gas, light and heavy oil and natural gas liquids. We make a concerted effort to have diverse exposure to both crude oil and natural gas to limit the price risk associated with any one commodity. While our recent focus has been on acquiring and developing natural gas assets, we will also continue to develop and add to our oil producing areas.

SINCE NO ONE PROPERTY REPRESENTS MORE THAN 5% OF OUR TOTAL PRODUCTION, THE RISK OF A SIGNIFICANT PRODUCTION INTERRUPTION IS LOW

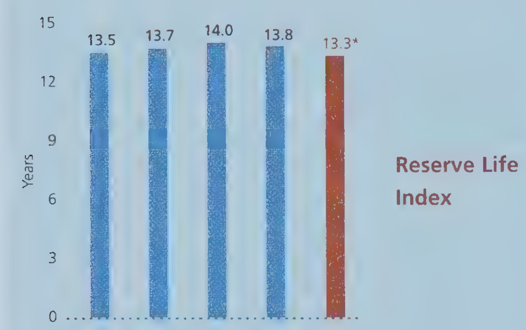
Top Producing Properties

Business Unit	Property	Operations	Type	2003 Avg. BOE/day	% of Total	P+P RLI*
Eastern	Joarcam	Operated	oil waterflood	3,308	5	8.7
Joint Venture	Deep Basin	Non-Operated	foothills gas	3,266	5	6.8
Central	Pembina 5 Way	Operated	oil waterflood	2,553	4	29.0
Southern	Bantry	Operated	shallow gas	2,406	3	14.6
Central	Pine Creek	Both	natural gas	2,195	3	9.7
Joint Venture	Mount Benjamin	Non-Operated	foothills gas	2,164	3	16.8
Southern	Hanna Garden	Operated	shallow gas	2,118	3	29.1
Northern	Valhalla	Both	oil and gas	2,094	3	9.0
Central	Ferrier	Both	natural gas	1,979	3	8.7
Southern	Verger	Both	shallow gas	1,931	3	17.5
Eastern	Giltedge	Operated	oil waterflood	1,919	3	15.0
Southern	Medicine Hat	Operated	oil waterflood	1,827	3	30.9
Northern	Progress	Both	oil and gas	1,684	2	5.3
Central	Sylvan Lake	Operated	oil and gas	1,313	2	6.4
Eastern	Gleneath	Operated	oil waterflood	1,213	2	27.1
Southern	Med. Hat/Sun Valley	Operated	shallow gas	1,098	2	17.2

*calculated using proved and probable reserves at December 31, 2003 and 2004 forecast production.

Long Life Assets

ENERPLUS ENJOYS ONE OF THE LONGEST RESERVE LIFE INDICES IN THE SECTOR. THIS HELPS SUSTAIN DISTRIBUTIONS OVER THE LONG-TERM



*Calculated using Proved + Probable reserves in 2003
Established reserves used in all prior years

Business Units

1 Northern
2 Southern
3 Eastern
4 Central
5 Joint Venture Non-Operated (included in all units)

Enerplus has maintained one of the longest proved and probable reserve life indices in the sector at 13.3 years.

OUR LONG RLI IS A COMPETITIVE ADVANTAGE AS IT REFLECTS A LOWER DECLINE RATE ON OUR EXISTING PRODUCTION, REDUCING THE DEVELOPMENT CAPITAL NEEDED FOR REINVESTMENT TO MAINTAIN PRODUCTION

This allows us to more prudently develop our properties over time, thereby reducing the risk of over committing capital before a project is proven. Traditional exploration and production companies are driven to accelerate production to maximize cash flow for reinvestment and typically have a much shorter RLI. At times, they also have a greater risk of over committing on a project in an effort to accelerate production additions. We believe our lower risk approach provides more stable cash flow and distributions over the long-term which is critical to our yield-oriented business model.

In 2002, Enerplus reorganized its operations into four operated and one joint venture business unit. This organizational structure provides improved operational and technical focus resulting in superior operating and capital efficiencies. It supports the opportunity for growth in each of the business unit areas. Each of the five business units represents its own profit centre with a complement of engineers, geologists, operators, landmen and support personnel.

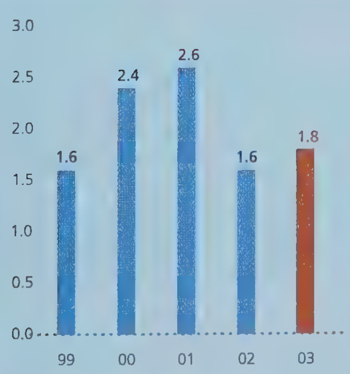
Focus on Value Creation

ENERPLUS FOCUSES ON OPPORTUNITIES WHERE WE HAVE A COMPETITIVE ADVANTAGE

Enerplus focuses its acquisition and capital development program on areas where we enjoy a competitive technical or operating advantage. These areas include shallow natural gas, crude oil waterfloods and deep foothills natural gas and have resulted in production increases that help to offset the natural decline of our asset base. Our strategy has been to develop a strong position in each asset class through both operated and non-operated interests. This focus provides meaningful direction to our ongoing acquisition and divestment efforts as we continually upgrade our asset base.

As a result of these efforts, Enerplus has maintained an attractive finding, development and acquisition cost ("FD&A") on a proved plus probable basis over time. Our three-year FD&A cost using the new NI 51-101 methodology is among the best in our sector at $8.54 per BOE or $7.86 per BOE using the historical methodology.

WE ALSO ENJOYED AN ATTRACTIVE RECYCLE RATIO OF 1.8 IN 2003 USING OUR NETBACK DIVIDED BY OUR FD&A COSTS



Recycle Ratio

This metric is indicative of the value created by our investment activities. The higher the recycle ratio, the better the profitability, with a recycle ratio below one representing negative value creation.

While overall corporate performance is reflected by the above FD&A and recycle ratios, the activities which are driving this performance centre around shallow gas, crude oil waterfloods and foothills gas development projects which are detailed following.

SHALLOW NATURAL GAS DEVELOPMENT

SHALLOW NATURAL GAS PRODUCTION HAS GROWN 600% OVER THE LAST FIVE YEARS TO ALMOST 70 MMCF/DAY (11,500 BOE/DAY) PRIMARILY THROUGH ACQUISITIONS, DEVELOPMENT DRILLING AND OPTIMIZATION TECHNIQUES

Enerplus has created significant value over the last five years from our shallow natural gas areas. Natural gas production from this asset base has grown 600% in the last five years to approximately 70 MMcf/day (11,500 BOE/day) primarily through targeted acquisitions, development drilling and optimization techniques. Enerplus has drilled in excess of 800 shallow gas wells over the last five years. In 2003, we drilled 250 shallow natural gas wells and spent approximately $42 million to bring on 2,150 BOE/day at an average on-stream cost of $19,488/BOE/day.

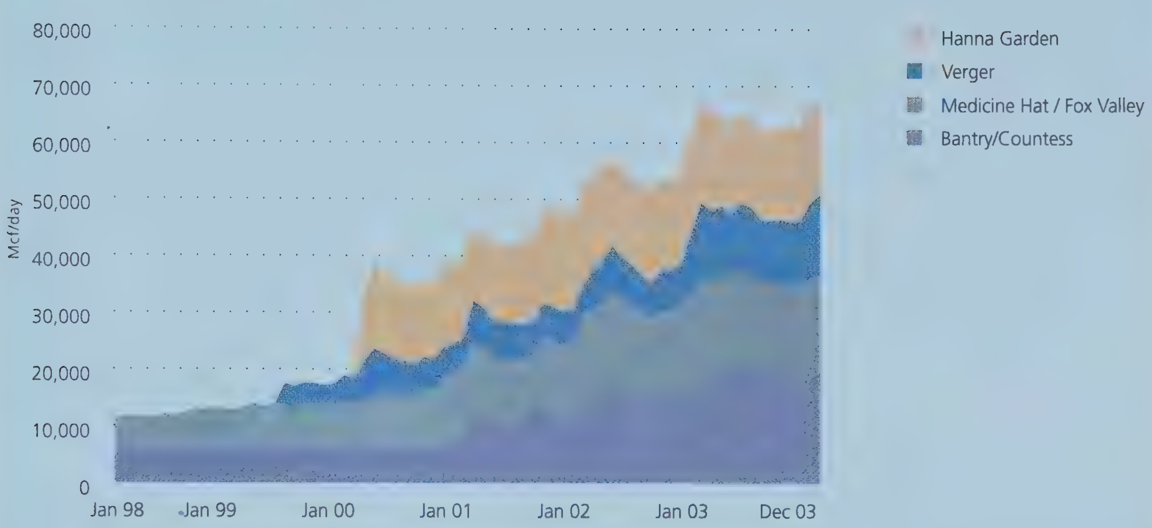
Rising natural gas prices have provided a dual benefit to shallow gas development in that it has generated both higher cash flows on current production and provided compelling economics for infill drilling. Our ability to execute cost-effective, multi-well shallow gas drilling programs has been instrumental to our success.

We see additional drilling and development opportunities in the years ahead and plan to spend approximately $38 million on shallow gas opportunities in 2004. As part of this investment, we plan to follow-up on successful increased density drilling initiated in 2003 and will also continue traditional infill drilling and optimization activities throughout our asset base.

2003 Key Shallow Gas Infill Drilling Projects

Area	Capital Spending ($millions)	IP Rate (BOE/day)	Initial On-Stream Cost $/BOE/Day
Bantry/Countess	$ 18.2	870	$ 20,920
Medicine Hat/Fox Valley	12.3	400	30,750
Hanna Garden	6.1	280	21,786
Verger	5.3	600	8,833
Total	**$ 41.9**	**2,150**	**$ 19,488**

Shallow Gas Production Growth



WATERFLOOD DEVELOPMENT

SINCE 2001, PRODUCTION HAS GROWN AS A RESULT OF OUR WATERFLOOD DEVELOPMENT AND ACQUISITION ACTIVITIES, MORE THAN OFFSETTING NATURAL PRODUCTION DECLINES

Enerplus operates 15 crude oil waterfloods with over one billion barrels of original oil reserves in place that produced approximately 18,000 BOE/day in 2003. These assets provide significant opportunity to enhance production and increase the recoverable portion of these reserves. Since 2001, production has gradually grown as a result of our development and acquisition activities, more than offsetting natural production declines. Last year, we spent $31.8 million on major development projects and brought on 1,965 BOE/day for an average on-stream cost of $16,183 BOE/day.

GIVEN THE LARGE ORIGINAL OIL IN PLACE, EACH ADDITIONAL ONE PERCENT IMPROVEMENT IN RECOVERY HAS THE POTENTIAL TO ADD 10 MILLION BARRELS OF RECOVERABLE OIL RESERVES

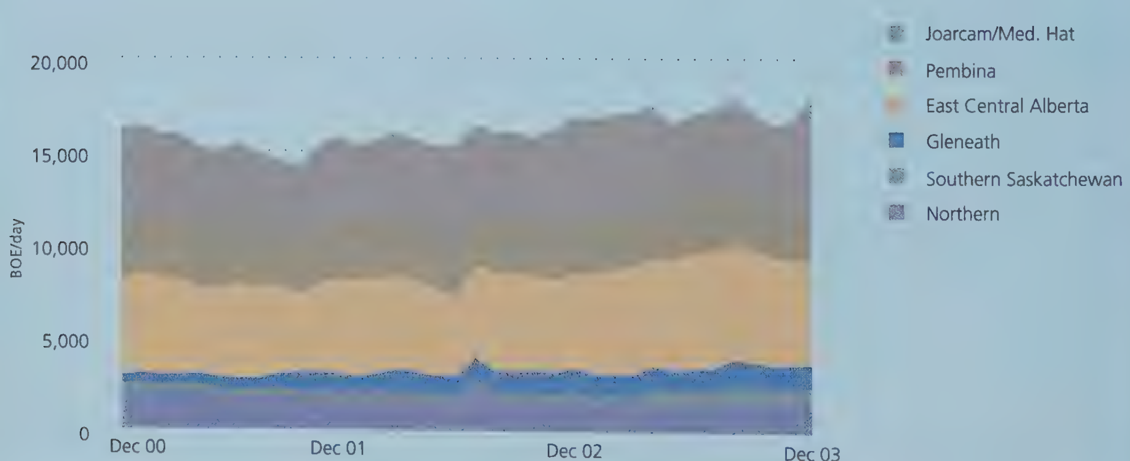
With an average recovery factor of 19% to date, over 80% of the original oil remains unrecovered. Typically these fields have higher operating costs given the significant water handling and electrical costs involved. However, effective management of these costs can increase profitability and extend the economic life of the field.

Enerplus has developed a core competency in waterflood application and we plan to spend an additional $27 million on these opportunities in 2004. An example of this competency is our successful acquisition and waterflood implementation at the Medicine Hat Glauconitic "C" property where we anticipate incremental reserve recovery of 1.3 MMBOE. We are currently performing integrated field reviews and operating cost reviews on all our waterfloods to ensure optimal recovery, production rates and decreased costs are achieved from this resource base.

2003 Key Waterflood Drilling and Optimization Projects

Area	Capital Spending ($millions)	IP Rate (BOE/day)	Initial On-Stream Cost $/BOE/Day
East Central Alberta	$ 14.9	980	$ 15,204
Northern	4.5	285	15,789
Joarcam/ Medicine Hat	6.3	360	17,500
Gleneath	3.1	180	17,222
Pembina	3.0	160	18,750
Total	**$ 31.8**	**1,965**	**$ 16,183**

Crude Oil Waterflood Production



JOINT VENTURE FOOTHILLS DEVELOPMENT

WHILE OPERATED PROPERTIES HAVE CREATED SIGNIFICANT VALUE FOR THE FUND, WE RECOGNIZE THE BENEFIT OF PARTICIPATING WITH EXPERIENCED PARTNERS ON MORE EXPENSIVE, TECHNICALLY CHALLENGING PLAYS

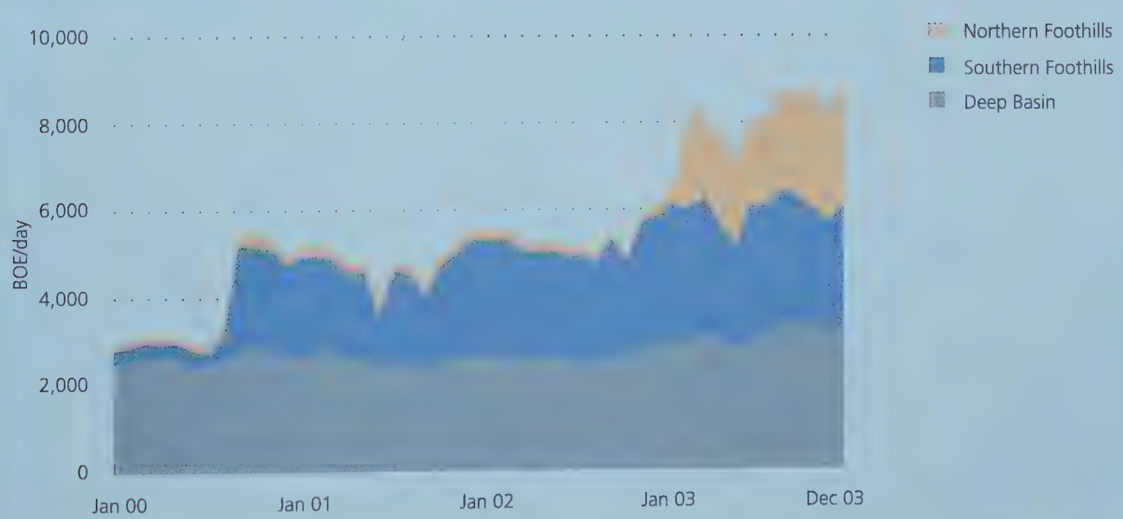
Enerplus has developed a significant non-operated production base of over 8,000 BOE/day from the deep foothills area of Alberta. This has been accomplished principally through strategic acquisitions and drilling participation with top tier operators. While operated properties have created significant value for the Fund, we recognize the benefit of participating with experienced partners on more expensive, technically challenging areas. This allows us to limit our risk on any single development project and minimize our overhead. We also gain valuable experience and exposure to a broad, attractive opportunity set that we can potentially apply to our operated properties.

Our strategy has been beneficial as we participated in approximately 95 gross wells (7 net wells) in 2003 for total costs of $21.4 million with 2,410 BOE/day of initial production at an attractive cost of $8,880/BOE/day. Overall, we expect to spend up to $20 million during 2004 in this area.

2003 Joint Venture Foothills Natural Gas Development Projects

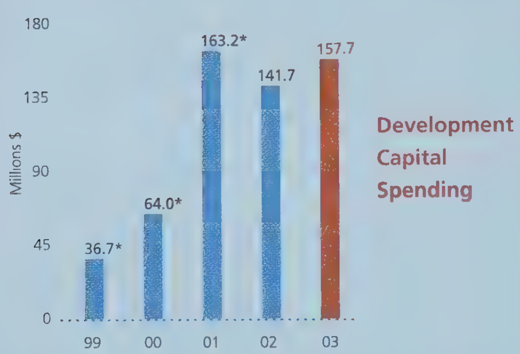
Area	Capital Spending ($millions)	IP Rate (BOE/day)	Initial On-Stream Cost $/BOE/Day
Deep Basin	$ 10.8	1,330	$ 8,120
Northern Foothills	8.4	980	8,571
Southern Foothills	2.2	100	22,000
Total	**$ 21.4**	**2,410**	**$ 8,880**

Joint Venture Foothills Production

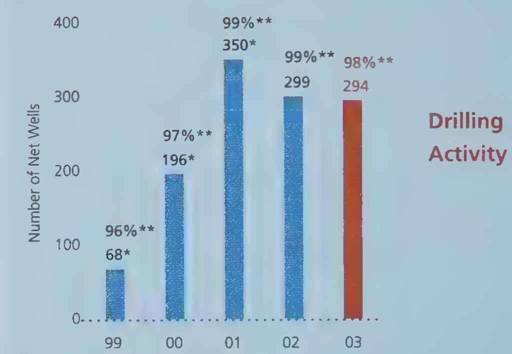


Active Developer

ENERPLUS PARTICIPATED IN DRILLING 294 NET WELLS WITH A 98% SUCCESS RATE IN 2003



* Enerplus & EnerMark combined



* Enerplus & EnerMark drilling results combined
** Denotes success rate

In 2003, Enerplus had another very active drilling year, participating in 543 gross wells including 316 gross operated and 227 gross non-operated wells. Overall, 294 net wells were drilled during 2003 with a 98% success rate. Although our gross wells were up year over year, our net wells decreased slightly due to our lower average working interest per well.

THIS MARKS THE THIRD CONSECUTIVE YEAR THAT ENERPLUS HAS INVESTED IN EXCESS OF $140 MILLION INTO THE DEVELOPMENT OF OUR ASSET BASE

The majority of our 2003 wells were drilled in southern Alberta and southwest Saskatchewan in the operated shallow gas regions of Medicine Hat, Verger, Countess, Hanna Garden, Bantry and Fox Valley. We also saw a marked increase in non-operated drilling in 2003 primarily in the deep basin and foothills natural gas regions.

2003 Drilling Activity

	Crude Oil Wells		Natural Gas wells		Dry & Abandoned Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Operated	27.0	24.4	284.0	238.6	5.0	4.0	316.0	267.0
Non-Operated	65.0	5.7	157.0	20.5	5.0	0.6	227.0	26.8
Total	**92.0**	**30.1**	**441.0**	**259.1**	**10.0**	**4.6**	**543.0**	**293.8**

Positioning for the Future

ENERPLUS IS INVESTING IN LONG-TERM OPPORTUNITIES SUCH AS OIL SANDS SAGD PROJECTS AND NATURAL GAS FROM COAL

OIL SANDS SAGD DEVELOPMENT

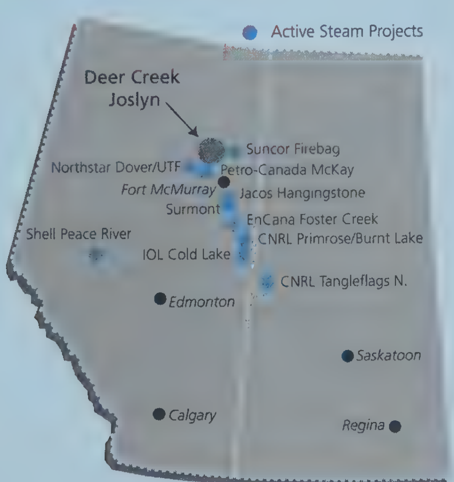
The development and production of Canada's oil sands is expected to grow significantly during the next decade offsetting declines in conventional oil production.

THIS VAST ASSET BASE HAS OVER 175 BILLION BARRELS OF RESERVES AND ONE MILLION BBLS/DAY OF PRODUCTION FROM CURRENT OIL SANDS MINING AND IN-SITU DEVELOPMENTS.

Approximately 80% will be exploited using proven in-situ technology such as steam assisted gravity drainage.

Enerplus is positioned to participate in this development through its ownership of a 16% working interest in Oil Sands Lease #24 ("Joslyn Creek") acquired in 2002 for approximately $16.4 million. Located in the Athabasca Oil Sands fairway of northeastern Alberta near other significant oil sands projects, Joslyn Creek has both SAGD and mining potential. To date, several hundred core holes have been drilled and evaluated on the lease to quantify the resource potential. Phase one of the SAGD commercial project is currently being completed and consists of a 600 bbl/day prototype. Initial production is expected in the second quarter of 2004 with peak production expected in 2005.

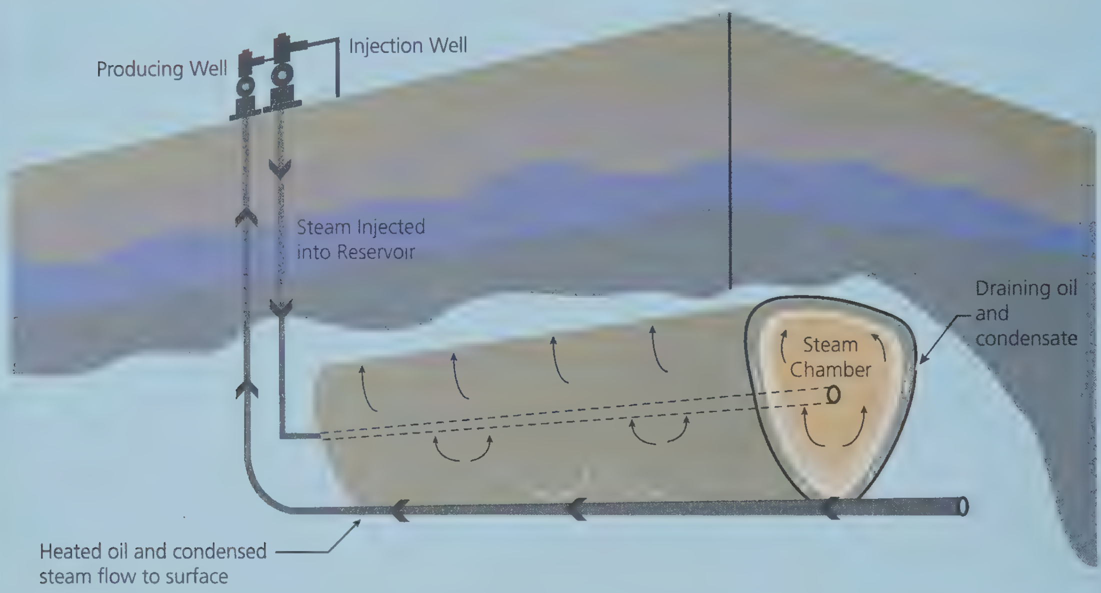
Oil Sands Development



Following the prototype, a full-scale 10,000 bbl/day project is anticipated to be completed and producing by 2007. The operator is also completing a feasibility study on the mining portion of the lease. Enerplus expects to record reserves as the resources are developed over time.

SAGD is an exploitation process where two horizontal wells are drilled approximately five metres apart with a five metre lateral offset. Steam is injected into the reservoir through the upper wellbore allowing the steam to permeate the oil sand, heating the oil and thus reducing the oil viscosity. The steam chamber grows over time, causing the heated oil to move down into the lower producing wellbore and flow to the surface.

SAGD Illustration



NATURAL GAS FROM COAL

ENERPLUS IS POSITIONING ITSELF TO EXPLOIT THIS OPPORTUNITY THROUGH ITS EXISTING LAND BASE WITH A NUMBER OF SMALL-SCALE PILOT PROJECTS AND SELECT COMMERCIAL PROJECTS THROUGHOUT ALBERTA

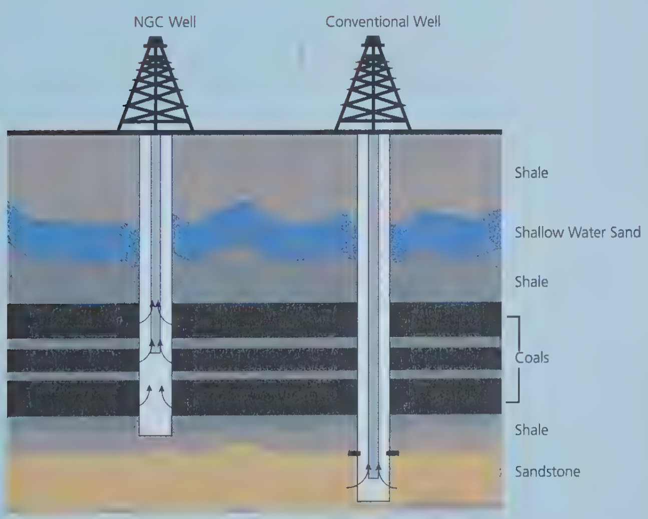
NGC, or coalbed methane, has significant upside potential in Canada as a number of industry players have been pursuing commercial projects across western Canada. The size of the NGC resource in western Canada has been estimated to be between 100 trillion and 550 trillion cubic feet of gas-in-place. Uncertainty surrounding the cost-effective recovery of these resources has placed the estimate of recoverable reserves in the range of 20 to 60 trillion cubic feet. More than 800 NGC wells have

been drilled in Canada to date, with another 750 planned for 2004 as the industry begins to pursue production from 14 core areas. The prospect of stable, long-life reserves combined with a different risk profile than that of conventional oil and gas operations makes NGC an attractive opportunity for the industry.

Enerplus is positioning itself to exploit this opportunity through its existing land base with a number of small-scale pilot projects and select commercial projects throughout Alberta. We are also participating with a key NGC partner on a mid-sized commercial project in central Alberta. We have evaluation projects underway in the Belly River, Horseshoe Canyon, and Ardley coals areas and additional interests in the Mannville areas. Enerplus also has extensive shallow gas processing facilities and gathering pipelines already in place that could provide valuable infrastructure in developing various NGC projects.

We plan to spend approximately $10 million on current NGC projects in 2004. This includes two commercial development projects and further appraisal drilling in four other areas to confirm the viability of these projects. If successful, we could expand our pilot areas.

Natural Gas from Coal Diagram

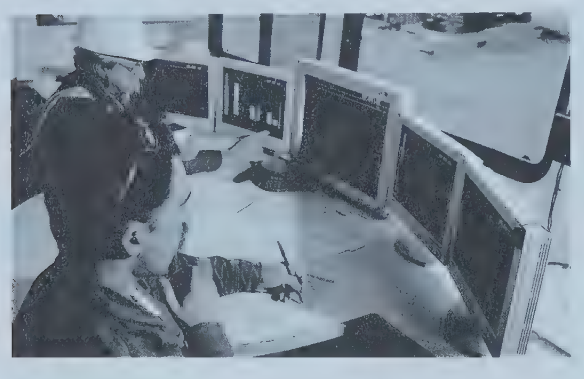


Unlike a traditional natural gas reservoir where gas occupies the space between rock particles, NGC involves extracting gas molecules from coal deposits.

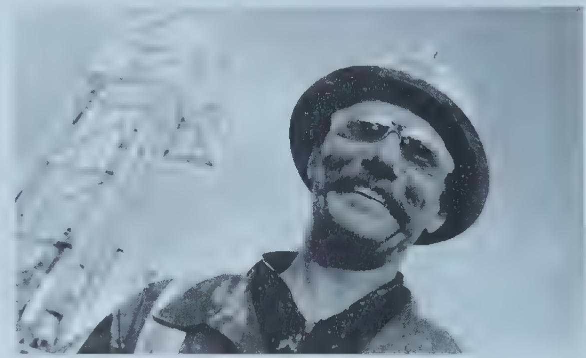
Knowledge & Expertise

THE SUCCESS WE HAVE ACHIEVED CAN BE DIRECTLY ATTRIBUTED TO OUR EMPLOYEES

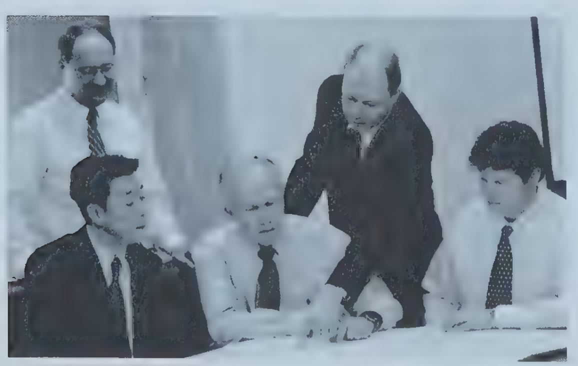
As we have grown our asset base throughout the years, we have also grown our employee base, not only in numbers but in knowledge and expertise. Our success is directly attributable to the dedication and commitment of our staff.



Active Developer
Our team includes drilling, facility, land and EH&S personnel which execute our development plans in the field.



Operations Focused
The knowledge and dedication of our field personnel are a critical component of the success of our operations. The day-to-day management of our assets maximizes results and ensures safe and reliable operations.



Value Creation
Our full complement of geologists, engineers, landmen, operators and support staff put their expertise to work as a team to enhance the value of our asset base.

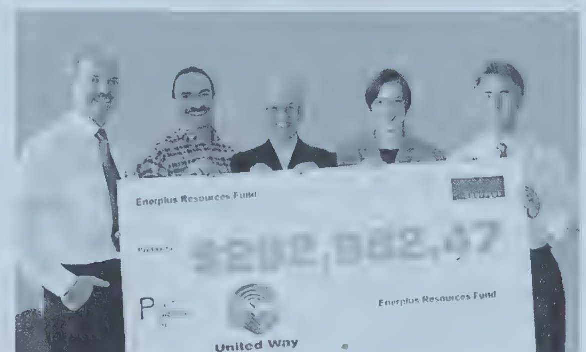
Technology and Innovation
Our people maximize the use of technology to realize the full potential of our assets.

Disciplined Portfolio Management

A keen understanding of the technical opportunities and the fundamentals of our business model help us make accretive acquisitions that will add to the future success of Enerplus.

Employee Training and Development

Training and employee development is critical to our future. Establishing goals and objectives helps our employees develop new skills while providing a meaningful contribution to Enerplus.



Stewardship and Strategic Planning

The on-going review of our operations enables us to identify opportunities early and plan for the future. We conduct regular stewardship reviews and strategic planning sessions that involve a broad cross-section of the Fund to improve our business decisions.

Good Corporate Citizens

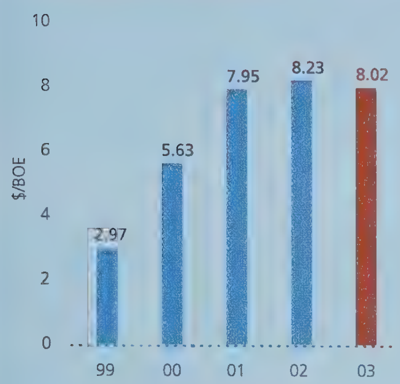
Enerplus encourages and supports community involvement and is a key contributor to the United Way and other worthwhile charities.

Investing for the Future

We have also established a variety of educational scholarships to further the development of talented students into the oil and gas sector.

OUR 2003 BUSINESS INITIATIVES WILL POSITION US TO DELIVER STRONG RESULTS INTO THE FUTURE

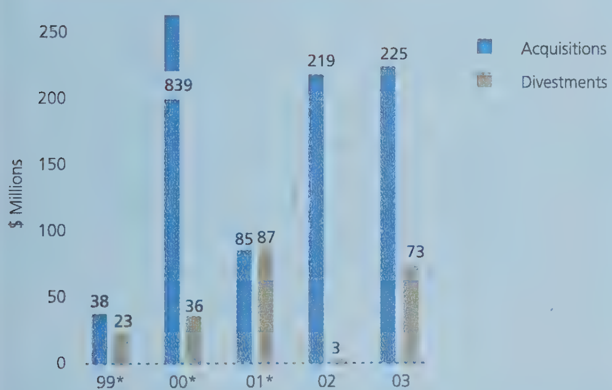
Acquisition Cost/BOE*



*Based on established reserves of Enerplus & EnerMark combined

Our disciplined acquisition approach has kept our costs low despite increasing oil and gas prices.

Acquisition & Divestment Activity*



*Enerplus & EnerMark combined

We continue to add to our asset base and divest of non-core assets as part of our on-going portfolio management

disciplined portfolio management

Growth Through Disciplined Portfolio Management

ENERPLUS WAS ABLE TO REPLACE OVER 75% OF ITS DAILY PRODUCTION VOLUMES IN 2003 THROUGH NET ACQUISITION ACTIVITIES. BY INCLUDING RESERVE REVISIONS FROM DEVELOPMENT ACTIVITY, OUR PRODUCTION REPLACEMENT INCREASED TO 99%

2003 was another successful year for acquisitions at Enerplus. We added to our core properties in the non-operated foothills, shallow natural gas and waterflood areas, spending $225.3 million to acquire 28.1 million BOE of proved plus probable reserves, 87% of which were proved. Significant transactions included PCC ($166.9 million), Freda Lake ($15.2 million) and various interests in the Joarcam area ($16.4 million).

In addition, we divested of $73.2 million of non-core properties with associated production of approximately 3,000 BOE/day and established reserves of 9.2 million BOE. These properties were generally small working interests in non-operated areas with low upside potential. Enerplus realized metrics of $7.96/BOE and $24,376/BOE/day on these dispositions. Given the size, low percentage of Proved Developed Producing ("PDP") reserves, a 5.0 year PDP RLI, and high operating costs associated with these assets, these metrics are quite favourable. We will continue the process of acquiring new properties and rationalizing marginal properties throughout 2004.

2003 Acquisition and Divestment Summary

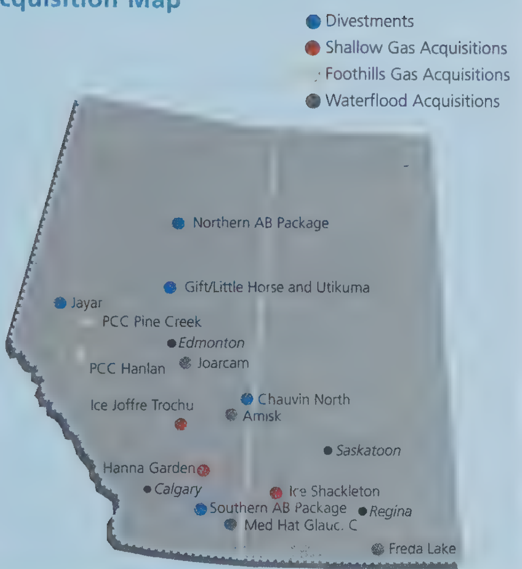
	Cost/Proceeds ($millions)	Estab. Reserves MMBOE [1]	Production BOE/day	Cost/Estab. Reserves[2] ($/BOE)	Cost/Production[2] ($/BOE/Day)
Acquired	225.3	28.1	5,595	$8.02	$40,268
Divested	73.2	9.2	3,003	$7.96	$24,376
Net	152.1	18.9	2,592		

[1] Based on established reserves as determined at the time of the acquisition or disposition. Changes, if any, associated with NI 51-101 were captured under revisions at year end.

[2] Based on initial cost excluding future development costs if any.

Value Creation Key to Acquisition

Acquisition Map



OUR ACQUISITION COST WAS AN ATTRACTIVE $8.02 PER ESTABLISHED BARREL OF OIL EQUIVALENT ACQUIRED

In 2003, we continued to focus our acquisition activities on assets where we have a competitive advantage. These include executing low-risk development drilling programs, increasing reserve recovery through waterflood optimization and low cost well recompletions. Recent acquisitions where these advantages exist include shallow gas drilling in Shackleton (Ice Energy), waterflood expansion in Joarcam, infill drilling in the Northern Foothills area (PCC), NGC development in Joffre (Ice Energy) and oil recompletions at Freda Lake.

In 2003, we capitalized on the value of the Celsius assets acquired in late 2002 through significant shallow natural gas development. This has resulted in production increasing from 4.5 MMcf/day to 9 MMcf/day on key shallow gas properties since the acquisition.

PCC ACQUISITION

The acquisition of PCC Energy Inc. and PCC Energy Corp. closed March 5, 2003 at a price of $166.9 million for 16.5 MMBOE of established reserves. The PCC assets included principally non-operated interests in long life, high netback, natural gas properties with significant infill drilling upside. The properties are located primarily in the central foothills area of Alberta and included a strategic interest in the 300 MMcf/day Hanlan Robb Gas Plant.

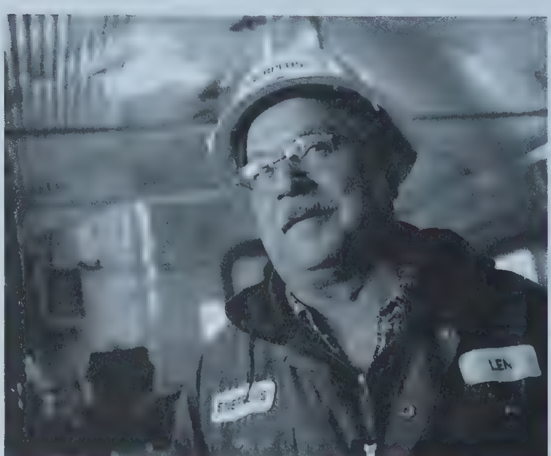
Equity Investment Strategy

Enerplus implemented a new strategy in 2003 of making equity investments in selected junior oil and gas exploration companies.

THE STRATEGY IS DESIGNED TO CREATE A LIMITED NUMBER OF RELATIONSHIPS WITH MANAGEMENT TEAMS WHO CAN PROVIDE VALUE THROUGH TECHNICAL INSIGHT IN OUR CORE AREAS, STRATEGIC ACQUISITIONS, PARTNERING OPPORTUNITIES AND VALUE ON THE EQUITY INVESTMENT ITSELF

During the year, Enerplus invested a total of $7.4 million, including an investment in Ice Energy. The initial investment in Ice Energy facilitated our acquisition of the entire company in early 2004.

Enerplus plans to pursue this investment strategy on a limited basis and expects our exposure to be approximately $10 million at any one time. We will be highly selective and will only invest with management teams that have a good strategic fit with Enerplus and an attractive investment risk/return profile.



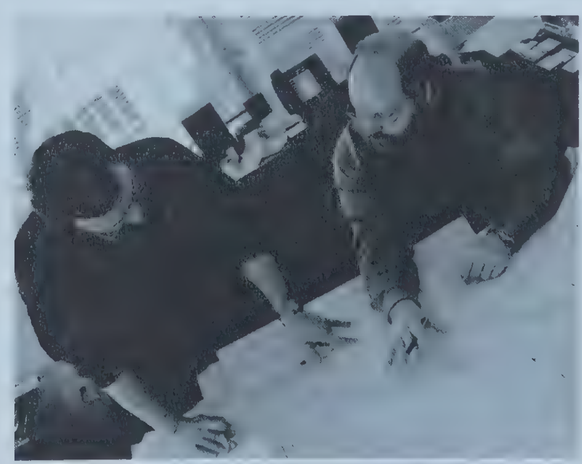
Subsequent Acquisition of Ice Energy Ltd.

On January 7, 2004, Enerplus acquired all of the outstanding shares of Ice Energy, a private company focused on shallow natural gas development in Saskatchewan and Alberta, for total consideration of $132.2 million.

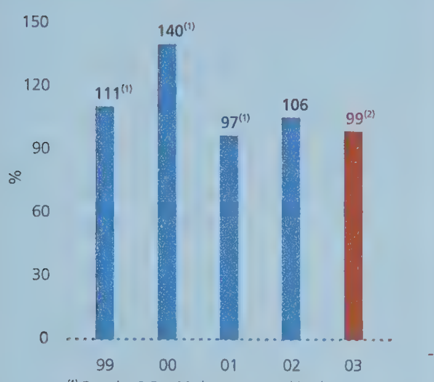
ICE ENERGY PROVIDES ENERPLUS WITH A NEW CORE SHALLOW GAS AREA WITH SIGNIFICANT DEVELOPMENT POTENTIAL IN THE SHACKLETON REGION OF WESTERN SASKATCHEWAN.

Production from Ice Energy was in excess of 2,300 BOE/day at closing and with anticipated development drilling, is expected to average 2,600 and 3,000 BOE per day in 2004 and 2005, respectively. We have identified over 250 shallow gas development drilling locations within the properties and estimate capital expenditures to be approximately $20 million and $25 million in 2004 and 2005.

A total of 13.9 MMBOE of proved plus risked probable reserves were acquired, based upon internal engineering estimates using the methodology prescribed in National Instrument 51-101. Included in the acquisition are 72,500 net acres of undeveloped land valued at approximately $9.2 million that will provide further development opportunities to the Fund. In addition, the Ice Energy assets include a 50% working interest in a NGC project.



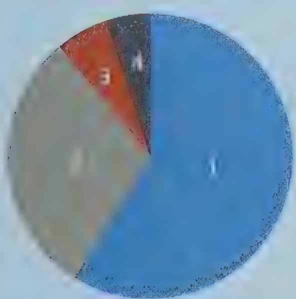
% Reserves Replacement



(1) Enerplus & EnerMark reserves combined
(2) 2003 reserves calculated using Proved + Probable reserves
Established reserves used in all prior years

Enerplus has consistently replaced its reserves year over year.

2003 Reserves Breakdown



1 Natural Gas 59%
2 Light & Medium Crude Oil 30%
3 Heavy Oil 6%
4 Natural Gas Liquids 5%

The mixture of commodities within our reserve base shows the diversity of our asset base.

diversity with longevity

Oil and Gas Reserves

YEAR OVER YEAR, PROVED PLUS PROBABLE RESERVES WERE ESSENTIALLY UNCHANGED VERSUS ESTABLISHED RESERVES LAST YEAR

Year-end 2003 reserves were evaluated in accordance with the newly introduced National Instrument 51-101 guidelines that were imposed by Canadian regulators earlier in the year. These guidelines are deemed to be more stringent and are intended to improve the consistency of reserve reports within the oil and gas sector. Enerplus' year end proved plus probable reserves were essentially unchanged from the established reserves reported in the prior year, going from 330.4 MMBOE in 2002 to 328.1 MMBOE in 2003, down 0.7%. Proved reserves, however, were more adversely affected by the more stringent regulations going from 288.3 MMBOE in 2002 to 249.2 MMBOE in 2003, down 13.6%. A portion of the negative proved revisions can be attributed to the new 50-year cutoff rule, which has virtually no impact on the Fund's production or net asset values.

Positive proved plus probable reserve revisions of 4.0 million BOE or 1.3% occurred as the effects of positive technical revisions exceeded the negative effects of NI 51-101. Proved reserve revisions were negative 31.0 MMBOE or 10.7%. Positive revisions associated with our development program of 10.9 MMBOE were more than offset by negative revisions of 41.9 MMBOE associated with NI 51-101.

NEW NI 51-101 RESERVE REPORTING RULES

Effective with the 2003 annual reporting cycle, Enerplus, and the majority of publicly traded Canadian oil and gas companies, are now subject to the Canadian reserve reporting requirement known as National Instrument 51-101. This new reporting requirement includes a number of rules and standards that were designed to improve consistency and reliability of Canadian public oil and gas reserve disclosures. The most significant changes associated with NI 51-101 include:

- the introduction of a 50-year cutoff which eliminates any reserves expected to be produced after 50 years;
- a more rigorous risking of probable reserves;
- a more stringent definition of proved reserves; and
- inclusion of future development costs when calculating finding and development costs.

While many fields produce much longer than 50 years, the 50-year cutoff was introduced to provide a consistent cutoff point in standardizing reserve reporting. This change impacts the reserve volumes for longer life entities, such as Enerplus, but does not have a material impact on current net asset values as these reserves have limited present value.

Another key change associated with NI 51-101 was the introduction of proved plus probable reserves (risked) to replace the previously used "established reserves" (proved plus half probable). Essentially each of these two definitions are designed to provide the most likely reserve estimate and we have used the two terms for comparison purposes throughout this report.

The third key change associated with NI 51-101 was a more conservative standard around reporting proved reserves. Traditionally, proved reserves represented a conservative estimate of the aggregate expected reserves. NI 51-101 introduced increased conservatism in an effort to limit potential negative proved reserve revisions. This higher standard has generally resulted in lower reported proved reserves across the Canadian industry this year.

The final major change requires future development capital to be included when calculating finding and development costs. Accordingly, we have included future development capital in our calculation of FD&A costs. This puts developed and undeveloped reserves on a more consistent basis for more meaningful comparisons across the industry.

RESERVE REPORTING

Given the new rules in place this year, comparisons to prior years are more difficult. To assist investors, we have provided disclosure that highlights reserve changes and associated metrics to allow comparisons year-over-year under the prior methodology (without NI 51-101) and with the new reporting rules (with NI 51-101). We have also adopted the practice of reporting proved plus probable reserves in 2003 whereas we previously reported established reserves. This type of reporting provides a clearer picture of reserve performance and changes during this transition year as the industry applies the new standards.

NI 51-101 has additional reporting requirements that provide more fulsome disclosure to investors and standardized the methods of calculating certain metrics. Additional information with regard to net reserves and constant prices will be contained in our Annual Information Form. All references to barrels of oil equivalent utilize a conversion rate of six Mcf of natural gas to one barrel of oil.

2003 RESERVE SUMMARY

2003 Reserve Summary – Gross Company Interest Volumes

	light & medium oil Mbbls	heavy oil Mbbls	total oil Mbbls	natural gas liquids Mbbls	natural gas Bcf	2003 total MBOE
Proved developed producing	74,558	11,301	85,859	11,846	737	**220,605**
Proved developed non-producing	97	63	160	517	26	**5,061**
Proved undeveloped	1,388	3,656	5,044	1,208	104	**23,502**
Total Proved Reserves	76,043	15,020	91,063	13,571	867	**249,168**
Probable Reserves	23,206	4,601	27,807	3,742	284	**78,898**
Total Proved Plus Probable Reserves	**99,249**	**19,621**	**118,870**	**17,313**	**1,151**	**328,066**

RESERVE RECONCILIATION

Proved Reserves - Gross Company Interest (forecast prices)

	light & medium oil Mbbls	heavy oil Mbbls	total oil Mbbls	natural gas liquids Mbbls	natural gas Bcf	total MBOE
Proved Reserves at Dec. 31, 2002	87,330	17,917	105,247	16,036	1,002	**288,267**
Acquisitions	8,841	24	8,865	805	88	**24,337**
Divestments	(5,226)	(16)	(5,242)	(259)	(10)	**(7,168)**
Extensions	372	0	372	94	9	**2,025**
Technical Revisions excl. NI 51-101	6,738	607	7,345	12	2	**7,647**
Discoveries	0	0	0	0	0	**0**
Economic Factors	(517)	408	(109)	13	8	**1,273**
Improved Recovery	0	0	0	0	0	**0**
Production	(7,466)	(1,512)	(8,978)	(1,703)	(88)	**(25,336)**
Reserves at Dec. 31, 2003 excl. NI 51-101	**90,072**	**17,428**	**107,500**	**14,998**	**1,011**	**291,045**
NI 51-101 50 Year Cut-off	(6,211)	0	(6,211)	(567)	(18)	**(9,778)**
Other NI 51-101 Revisions	(7,818)	(2,408)	(10,226)	(860)	(126)	**(32,099)**
Reserves at Dec. 31, 2003 incl. NI 51-101	**76,043**	**15,020**	**91,063**	**13,571**	**867**	**249,168**

Probable Reserves - Gross Company Interest (forecast prices)

	light & medium oil Mbbls	heavy oil Mbbls	total oil Mbbls	natural gas liquids Mbbls	natural gas Bcf	total MBOE
Half Probable Reserves at Dec. 31, 2002	13,169	3,556	16,725	2,318	139	**42,175**
Acquisitions	1,454	43	1,497	122	13	**3,769**
Divestments	(1,485)	(292)	(1,777)	(35)	(1)	**(2,034)**
Extensions	49	0	49	0	3	**541**
Technical Revisions excl. NI 51-101	2,548	(99)	2,449	4	0	**2,549**
Discoveries	0	0	0	0	0	**0**
Economic Factors	(824)	233	(591)	264	(3)	**(920)**
Improved Recovery	1,092	0	1,092	0	0	**1,092**
Production	0	0	0	0	0	**0**
Reserves at Dec. 31, 2003 excl. NI 51-101	16,003	3,441	19,444	2,673	151	47,172
NI 51-101 50 Year Cut-off	(2,976)	0	(2,976)	(312)	(22)	**(6,994)**
Other NI 51-101 Revisions	10,179	1,160	11,339	1,381	155	**38,720**
Reserves at Dec. 31, 2003 incl. NI 51-101	23,206	4,601	27,807	3,742	284	78,898

Proved plus Probable Reserves - Gross Company Interest (forecast prices)

	light & medium oil Mbbls	heavy oil Mbbls	total oil Mbbls	natural gas liquids Mbbls	natural gas Bcf	total MBOE
Estab. Reserves at Dec. 31, 2002	100,499	21,473	121,972	18,354	1,141	**330,442**
Acquisitions	10,295	67	10,362	927	101	**28,106**
Divestments	(6,711)	(308)	(7,019)	(294)	(11)	**(9,202)**
Extensions	421	0	421	94	12	**2,566**
Technical Revisions excl. NI 51-101	9,286	508	9,794	16	2	**10,196**
Discoveries	0	0	0	0	0	**0**
Economic Factors	(1,341)	641	(700)	277	5	**353**
Improved Recovery	1,092	0	1,092	0	0	**1,092**
Production	(7,466)	(1,512)	(8,978)	(1,703)	(88)	**(25,336)**
Reserves at Dec. 31, 2003 excl. NI 51-101	**106,075**	**20,869**	**126,944**	**17,671**	**1,162**	**338,217**
NI 51-101 50 Year Cut-off	(9,187)	0	(9,187)	(879)	(40)	**(16,772)**
Other NI 51-101 Revisions	2,361	(1,248)	1,113	521	29	**6,621**
Reserves at Dec. 31, 2003 incl. NI 51-101	**99,249**	**19,621**	**118,870**	**17,313**	**1,151**	**328,066**

Net Present Value of Future Production Revenue

These schedules have been prepared on the basis that no cash income tax will be paid by the Fund or its operating subsidiaries in the future and therefore after-tax future net revenues from oil and gas reserves is equal to before tax future net revenues from oil and gas reserves.

Under Enerplus' current structure and existing tax legislation, annual taxable income is transferred from its operating entities to the Fund through interest and royalty payments. The Fund, in turn, makes distributions to its unitholders and therefore does not incur any cash income tax in the operating companies or the Fund.

The following table shows the net present value of future production using the forecast prices.

Net Present Value of Future Production Revenue – Forecast Prices and Costs
($ millions including ARTC)

	0%	5%	10%	15%
Proved developed producing	$3,540	$2,264	$1,719	$1,414
Proved developed non-producing	82	56	43	35
Proved undeveloped	286	172	111	75
Total proved Reserves	3,908	2,492	1,873	1,524
Probable Reserves	1,303	601	360	249
Proved plus Probable Reserves at Dec. 31, 2003	**$5,211**	**$3,093**	**$2,233**	**$1,773**

Net Asset Value

Enerplus' net asset value is measured with reference to the present value of future net cash flows from our reserves as estimated by independent reserve engineers, Sproule Associates Limited ("Sproule"), plus land values, adjusted for working capital and long-term debt at year-end. This calculation can vary significantly depending on the oil and natural gas price assumptions used by Sproule. In addition, this calculation ignores "going concern" value and assumes only the reserves identified in the Sproule report with no further acquisitions, despite our 18 year history of replacing production through acquisitions and development.

Net Asset Value – Forecast Prices
($ millions, except per Trust Unit amount)

	0%	5%	10%	15%
Present value of proved plus probable reserves at Dec. 31, 2003	$5,211	$3,093	$2,233	$1,773
Undeveloped acreage and seismic (acreage valued at $50/acre)	17	17	17	17
Long-term debt	(338)	(338)	(338)	(338)
Net Working capital excluding distributions to unitholders	65	65	65	65
Net asset value	**$4,955**	**$2,837**	**$1,977**	**$1,517**
Net asset value per Trust Unit[1]	**$52.52**	**$30.07**	**$20.95**	**$16.08**

[1] Based on 94.3 million Trust Units outstanding as at December 31, 2003.

Reserve Determination Methodologies

Sproule has evaluated 86% of the total proved plus probable value (discounted at 10%) of the Fund's year-end reserves and has reviewed all the reserves internally evaluated by Enerplus in keeping with NI 51-101. All evaluations of future net production revenues set forth in the tables are stated without provision for income taxes, abandonment costs on existing wells and facilities or associated general and administrative costs.

Prior to this year, Enerplus followed the Canadian practice of using "Established Reserves", which included proved reserves and the probable reserves portion with a predetermined risk factor of 50%. This year, Enerplus followed the practice of reporting proved plus probable reserves with probable reserves risked by the third party engineering firm or our own internal evaluators in keeping with NI 51-101. In the U.S., reserve estimates are calculated using prices and costs held constant at amounts in effect at the date of the reserve report. Also in the U.S., proved reserves are reported excluding probable reserves and proved reserve standards in the U.S. may not be comparable to the Canadian standards used in NI 51-101. Generally, Canadian proved reserves are more conservative from U.S. proved reserves. In the U.S., only net production is typically reported. As a consequence, care should be used when comparing U.S. and Canadian style reserves and production between companies.

The present value of future cash flows at December 31, 2003 was based upon crude oil and natural gas pricing assumptions prepared by Sproule. The base reference prices and exchange rates used by Sproule are as follows:

Sproule January 1 **(forecast prices)**

	WTI crude oil $US/bbl	light crude[1] Edmonton $CDN/bbl	natural gas 30 day spot plant gate price $CDN/MMbtu	exchange rate $US/$CDN
2004	$ 29.63	$ 37.99	$ 5.81	$ 0.75
2005	26.80	34.24	5.15	0.75
2006	25.76	32.87	4.59	0.75
2007	26.14	33.37	4.71	0.75
2008	26.53	33.87	4.80	0.75
Thereafter	+1.5%	+1.5%	+1.5%	0.75

[1] Edmonton refinery postings for 40 degree API, 0.4% sulphur content crude

Finding, Development and Acquisition Costs

OUR THREE-YEAR FD&A COSTS, USING PROVED PLUS PROBABLE RESERVES, IS AMONG THE BEST IN OUR SECTOR AT $8.54 PER BOE USING THE NEW NI 51-101 METHODOLOGY AND $7.86 PER BOE USING THE HISTORICAL METHODOLOGY.

Enerplus has maintained an attractive finding, development and acquisition ("FD&A") cost on a proved plus probable reserves basis over time. Our three-year FD&A cost is among the best in our sector at $8.54 per BOE using the new NI 51-101 methodology and $7.86 per BOE using the historical methodology. We also enjoy an attractive three-year average recycle ratio of 1.9 on a proved plus probable reserves basis under NI 51-101. The recycle ratio is indicative of the value created by our investment activities. The higher the recycle ratio, the better the profitability of our investments. A recycle ratio of less than one represents negative value creation.

The following tables summarize Enerplus' FD&A costs on both a proved and proved plus probable basis under both the new NI 51-101 guidelines and the historic method for calculating FD&A. We have also included the recycle ratio on a proved plus probable basis. We believe FD&A and recycle metrics under the new NI 51-101 rules are comparable year-over-year when using established reserves for prior years and the new proved plus probable reserves for 2003. However, a comparison using proved reserves is problematic because of the more stringent rules applied this year. To assist investors in determining our FD&A performance this year in a historical context, we have included FD&A costs as determined under both the new and old methods.

FD&A for proved plus probable reserves did not materially change under the two methods ($8.54 per BOE under the new rules and $7.86 per BOE under the historic methodology) given the comparability of established and proved plus probable reserves used in the calculation. FD&A for proved reserves only changed materially given the significant difference in what constitutes proved reserves year-over-year. Under NI 51-101, we expect 2003 will form a new baseline for proved reserves that can be used to determine FD&A on a proved basis going forward. Historical comparisons, including three-year average FD&A, will continue to be problematic until three years of reserve numbers determined under the same rules are available.

The following schedule compares Enerplus' FD&A costs for the last three years on a proved plus probable basis under the new rules for NI 51-101 and the old method as historically reported.

FD&A Costs Under NI 51-101

($ millions, except per BOE amounts)

	2003	2002	2001
Proved Reserves			
Capital expenditures and net acquisitions	**309.8**	357.3	872.6
Net change in Future Development Costs	**(26.1)**	58.6	16.4
Gross company reserve additions (MBOE)	**(13.8)**	41.7	111.3
FD&A costs ($/BOE)	**N/A[1]**	9.97	7.99
Three-year average FD&A costs ($/BOE)[2]	**$ 11.41**	$ 8.48	$ 8.25
Proved plus Probable Reserves (Prior to 2003 – Established)			
Capital expenditures and net acquisitions	**309.8**	357.3	872.6
Net change in Future Development Costs	**(43.0)**	48.0	42.7
Gross company reserve additions (MBOE)	**23.0**	41.0	121.9
FD&A costs ($/BOE)	**11.60**	9.89	7.51
Three-year average FD&A costs ($/BOE)[2]	**$ 8.54**	$ 7.88	$ 7.48

[1] As the negative proved revisions during 2003 were greater than the reserve additions, the FD&A cost for 2003 is not determinable.
[2] Calculated as FD&A over a three-year period.

FD&A Costs Under Historic Methodology

($ millions, except per BOE amounts)

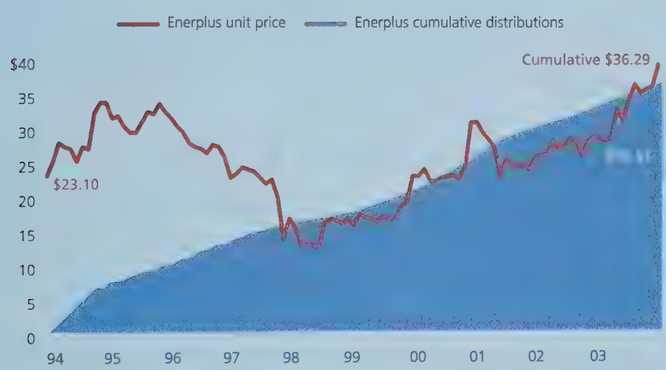
	2003	2002	2001
Proved Reserves			
Capital expenditures and net acquisitions[1]	**309.8**	357.3	872.6
Gross company reserve additions excluding NI 51-101 effects (MBOE)	**28.1**	41.7	111.3
FD&A costs ($/BOE)	**11.02**	8.57	7.84
Three-year average FD&A costs ($/BOE)[2]	**$ 8.50**	$ 8.08	$ 8.02
Proved plus Probable Reserves (Prior to 2003 – Established)			
Capital expenditures and net acquisitions[1]	**309.8**	357.3	872.6
Gross company reserve additions excluding NI 51-101 effects (MBOE)	**33.1**	41.0	121.9
FD&A costs ($/BOE)	**9.36**	8.72	7.16
Three-year average FD&A costs ($/BOE)[2]	**$ 7.86**	$ 7.46	$ 7.19

[1] Future Development Costs are excluded from all years.
[2] Calculated as FD&A over a three-year period.

Recycle Ratio

	2003	2002	2001
Operating netback ($/BOE)	**20.89**	15.50	19.61
Finding, development and acquisition costs ($/BOE)	**11.60**	9.89	7.51
Recycle ratio	**1.8x**	1.6x	2.6x
Three-year average Recycle ratio	**1.9x**	2.1x	2.3x

10 Year Performance



Enerplus has provided a 227% total return over the past 10 years.

responsible leadership

Corporate Governance

Enerplus believes that good corporate governance is essential to creating long-term value for our unitholders. Sustained financial success can only be achieved by operating with integrity and in an ethical manner. As such, Enerplus is committed to following corporate governance best practices.

The Board of Directors of EnerMark Inc. ("EnerMark"), a wholly-owned subsidiary of the Fund, is responsible for the overall governance of the Fund.

THE BOARD OF DIRECTORS

Currently, our Board is composed of nine directors. Seven of the directors are deemed to be "unrelated or independent" pursuant to the Toronto Stock Exchange ("TSX") guidelines and the New York Stock Exchange ("NYSE") listing standards, respectively. Throughout our disclosure of corporate governance practices, we will use the term "independent" to denote both independent and unrelated.

The Board is charged with the overall stewardship of the Fund and manages or supervises the business of the Fund and its management. Specifically, the Board's responsibilities include:

- approving the annual audited financial statements of the Fund;
- recommending to the unitholders the appointment of the Fund's external auditors;
- reviewing, adopting and monitoring the Fund's strategic planning process;
- approving goals and objectives for the Fund;
- reviewing and approving the Fund's operating budget;
- ensuring policies and processes are in place for the identification of principal business risks and reviewing and approving risk management strategies;
- approving corporate policies and other corporate protocols and controls;
- succession planning, including nominating and monitoring the Chief Executive Officer and senior management;

- approving the Fund's policy on public disclosure; and
- ensuring the integrity of internal financial controls and reviewing management information systems.

In addition, the Board has the responsibility at all times to act in the best interest of the Fund and its unitholders.

The Board meets a minimum of six times per year. Each scheduled board meeting is followed by a discussion of the independent directors without the presence of management. Directors assist in preparing the agenda for Board and committee meetings and receive a comprehensive package of information in advance of each meeting. Further, the Board attends an annual strategic planning session to review, amend or adopt new corporate objectives for the upcoming year and longer-term strategies.

BOARD INITIATIVES TO IMPROVE CORPORATE GOVERNANCE

The Board continually reviews its practices and procedures to ensure it follows corporate governance best practices. During 2003, the Board undertook a number of initiatives to improve its corporate governance practices. An example of this is the approval of a new Code of Business Conduct (the "Code") (following the internalization of the Fund's management company) which sets standards of ethical behaviour for the Fund and all of its affiliates. Each director, officer (including our principal executive officer, principal financial officer, principal accounting officer and controller), employee, and consultant must adhere to the standards described in the Code and must sign an acknowledgement of such standards and disclose any deviation from such standard each year. Prior to the adoption of the Code, the employees responsible for the Fund's management conducted themselves pursuant to the code of ethics of that manager's former parent company. The Code can be found, in its entirety, on our website at www.enerplus.com. As of March 17, 2004, no waivers have been granted pursuant to the Code of Business Conduct.

Other initiatives taken by the Board include: a review of director independence; mandating certain committee memberships be restricted to independent directors; and a review of committee charters to ensure best practices.

The current corporate structures, policies and practices of the Board and its committees has enabled the Board to conclude that Enerplus is in full compliance with the Guidelines of Corporate Governance established by the TSX, which is more particularly outlined in the Fund's Information Circular and Proxy Statement for its 2004 annual general meeting.

The Board of Directors discharges its responsibilities either acting in its entirety, or through one of its committees.

CORPORATE GOVERNANCE, NOMINATING AND ENVIRONMENT, HEALTH & SAFETY COMMITTEE

This Committee is comprised of three independent directors, appointed annually following the annual general meeting of the Fund. The purpose of this Committee includes:

Corporate Governance and Nominating

- assessing and making recommendations as to the size, composition and effectiveness of the Board;
- recommending nominees for election to the Board;
- conducting an annual self evaluation process of the Board and each of its directors;
- conducting an annual evaluation process to assess the effectiveness of the President & Chief Executive Officer;
- reviewing and monitoring the orientation of new directors;
- receiving annual compliance certificates from all employees, directors, officers and consultants; and
- generally ensuring good corporate governance practices are observed.

Environment, Health & Safety

- reviewing the Fund's environment, health and safety ("EH&S") programs and policies;
- reviewing management's performance relating to EH&S matters;
- reviewing significant external and internal EH&S reports on risk assessments, ongoing investigations and audits performed;
- ensuring that long-range preventive programs are in place to limit future risks;
- receiving an environment, health and safety compliance certificate from the Chief Operating Officer twice annually; and
- generally ensuring the integrity of the Fund's EH&S programs and policies.

COMPENSATION AND HUMAN RESOURCES COMMITTEE

The purpose of this Committee is to assist the Board in fulfilling its duties regarding human resources, compensation matters and succession planning. The Committee is composed of three independent directors. The Committee's responsibilities include:

- assessing the performance of the Chief Executive Officer and senior management with reference to corporate objectives;
- recommending executive compensation policies, programs and awards to the Board;
- reviewing and approving the granting of trust unit rights to officers and employees under the Trust Unit Rights Incentive Program and entitlements under the Full Value Unit Plan;
- reviewing and recommending to the Board awards under the Fund's performance incentive plan;
- reviewing compensation at all levels to ensure competitiveness and employee retention; and
- reviewing long-term succession plans for senior executive positions.

AUDIT AND RISK MANAGEMENT COMMITTEE

The Audit and Risk Management Committee is currently comprised of three independent directors, being Robert Normand, Chairman, Andre Bineau, and Harry Wheeler, all of whom are financially literate. Robert Normand, the Chairman of the Committee, is a Chartered Accountant and has been identified to be the Committee's "Financial Expert" under applicable U.S. reporting rules. The Committee is primarily responsible for the quality of the Fund's financial reporting and operates pursuant to a charter which identifies its objectives and responsibilities.

The Committee's responsibilities include:

- reviewing, with management and the external auditors, the interim and annual financial statements to be recommended for approval;
- ensuring the Chief Executive Officer and the Chief Financial Officer certify the accuracy of the information set forth in the consolidated annual financial statements and related disclosure materials of the Fund;
- reviewing with the external auditors the use by management of generally accepted accounting principles, their consistent application and their appropriateness;
- engaging the Fund's external auditors and assessing their performance annually;
- reviewing and approving the annual audit plan and audit fees;
- reviewing and approving non-audit services to be provided by the Fund's external auditors;
- reviewing financial reporting systems and monitoring management's initiatives with regard to internal controls;
- reviewing the processes by which management identifies, measures and manages the various financial risks of the business;
- reviewing the hedging and derivatives policies of, and transactions entered into by, management of the Fund; and
- meeting independent of management with the external auditors following each scheduled Committee meeting.

The charter of the Audit and Risk Management Committee can be found, in its entirety, on our website at www.enerplus.com.

The Committee implemented a policy to encourage employees and consultants to disclose any perceived acts or circumstances of financial or ethical misconduct which may impact the assets of the Fund or the interests of its unitholders. The Fund is been dedicated to the principles of honesty and integrity in all matters concerning the conduct of its business and it expects and believes that all employees and contract personnel share this commitment. As a result of this policy, any improprieties which are detected in the organization can be anonymously and directly reported to, among others, the Chairman of the Committee, on a confidential basis. Further, any person providing a report pursuant to this initiative shall be protected from any form of retaliation by any Fund personnel.

RESERVES COMMITTEE

The Reserves Committee is comprised of three independent directors. The Committee's responsibilities include:

- recommending to the Board the engagement of the independent reserves evaluator;
- assessing the work of independent reserves evaluator annually;
- reviewing the Fund's procedures relating to the disclosure of information with respect to its reserves;
- reviewing the scope of the annual review of the reserves by the independent reserves evaluator, including findings and any disagreements with management;
- meeting independent of management with the reserves evaluator;
- determining whether any restrictions affect the ability of the reserves evaluator in reporting on the Fund's reserves data;
- receiving, annually, a signed reserves evaluator's report and a certificate of compliance/due diligence from management; and
- approving the year-end reserves evaluation.

MANAGEMENT DISCLOSURE AND OVERSIGHT COMMITTEE

In addition to the Board committees, management has formed an internal committee to enhance and ensure the Fund meets its increasing disclosure obligations. As a foreign private issuer listed on the NYSE, the Fund abides by applicable U.S. law and regulations and generally follows the recommendations of the Securities Exchange Commission ("SEC") and the NYSE. The Committee reports to senior management, including the Chief Executive Officer and the Chief Financial Officer, and also serves as the coordinating group for the Fund's public disclosure. The Committee's responsibilities include:

- reviewing the Fund's internal financial controls and ensuring such controls are sufficient to discharge the Fund's legal and regulatory obligations;
- ensuring the Fund's internal financial controls are being observed by Fund personnel and are operating effectively;
- reviewing all periodic reports and disclosure documents; and
- reviewing news releases with respect to quarterly and annual financial results.

We believe our approach to corporate governance observes the best practices. Further, we are in compliance with the Toronto Stock Exchange Guidelines for Improved Corporate Governance in Canada. In this regard, we direct the reader to the Fund's Information Circular and Proxy Statement for its 2004 annual general meeting under the heading of "Statement of Corporate Governance Practices".

As a foreign private issuer listed on the NYSE, the Fund is required, pursuant to Section 303A.11 of the NYSE Listing Manual, to compare its corporate governance practices to the new NYSE corporate

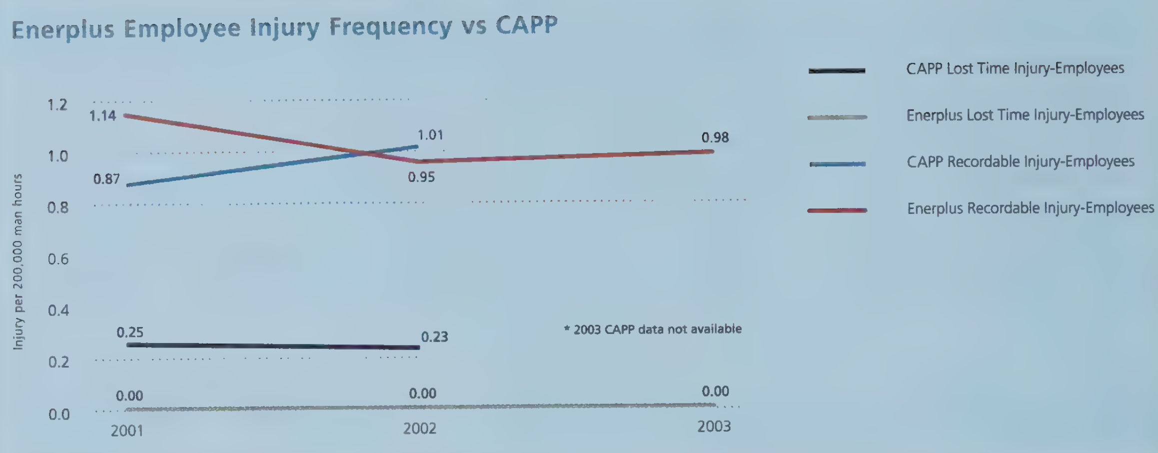
governance listing standards. We have undertaken a review of these new listing standards and confirm that the Fund's practices in corporate governance are not significantly nor materially different from such standards. As a foreign private issuer, we are not obligated to and we do not have an internal audit function. However, Enerplus is currently reviewing its position on this matter.

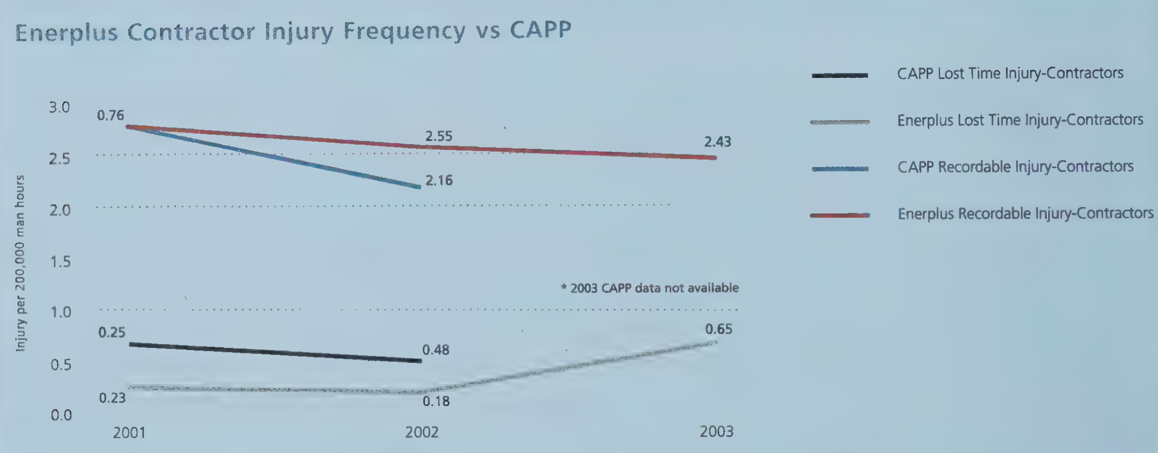
As a foreign private issuer, the Fund is also subject to certain reporting, disclosure and certification obligations in the United States. The Fund has complied with, and will continue to comply with, all of these obligations, including all required certifications by its Chief Executive Officer and Chief Financial Officer pursuant to the Sarbanes-Oxley Act as well as Canadian securities laws.

Environment, Health & Safety

Enerplus places a high priority on protecting our environment and the health and safety of our employees, contractors and the public. We recognize the value of maintaining superior environment, health and safety standards and actively manage programs to support and measure our efforts for further improvement.

Enerplus monitors the key industry benchmarks of recordable and lost time injuries for employees and contractors. Our results compare favourably to industry data as our employees have not experienced a lost time accident since 2000. We consistently outperform the employee lost time injury index as measured against benchmark data provided by CAPP (the Canadian Association of Petroleum Producers). However, this benchmark data highlights the need to improve our contractor safety performance and this will be a focus area in 2004.





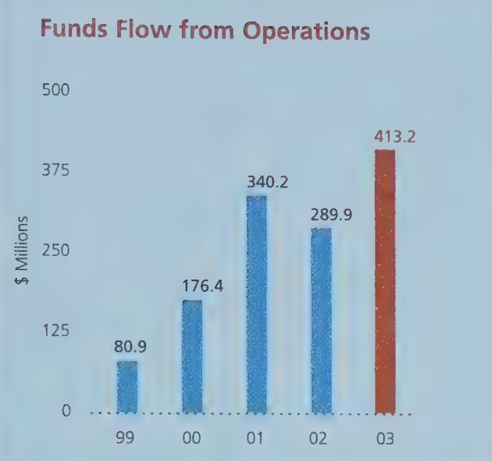
Our EH&S Management System includes other ongoing assessments designed to support top tier performance and continuous improvement as demonstrated by the following initiatives:

- Enerplus achieved a 94% rating from a third party audit conducted on our Certificate of Recognition in the Partnership Program with Alberta Human Resources and Employment and the Workers Compensation Board. This is an excellent accomplishment that demonstrates our drive for distinction within our program.
- Enerplus continues to participate at a Platinum Level, the highest level attainable, in the Environmental Health and Safety Stewardship Program initiated by CAPP.

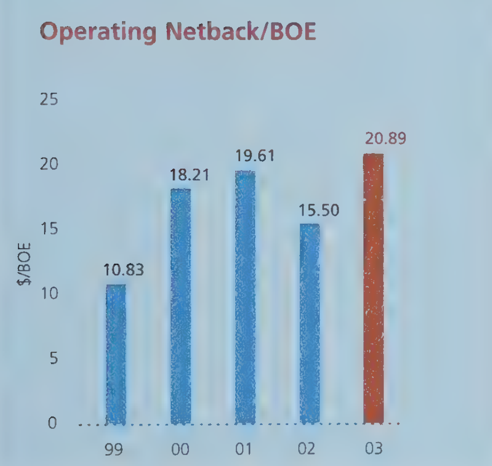
- An internal EH&S Steering Committee was formed, comprised of Executive, Managers and EH&S staff, to address environmental, health and safety standards and policies. Emphasis will include enhancements to programs to ensure hazardous tasks are carried out safely, responsibly and effectively.
- As part of our Corrosion Integrity Management Program, Enerplus continues to provide inspection and upgrading of our production infrastructure to minimize potential environmental and financial impacts. Last year, approximately 2,000 kilometres (43%) of our pipelines were flow modeled and risk assessed, 410 (25%) of our tanks were inspected or leak tested, and 100% of the required pressure vessels inspections were completed. Enerplus also successfully achieved the Alberta Boiler Safety Association ("ABSA") external three-year audit renewal.

COMMUNITY INVOLVEMENT

Enerplus is committed to investing in our local communities both in Calgary and throughout western Canada. We believe that as a responsible corporate citizen, we can contribute to the quality of life in the communities where we have operations. We do this by contributing to various community-based organizations that we believe maximize our charitable giving. Our employees are equally committed to the communities where they live and work. In 2003, through the efforts of our employees and a matching of their contributions, Enerplus was able to donate approximately $300,000 to the Calgary United Way. We are also a supporter of Habitat for Humanity and have joined forces with three industry partners to build two townhomes in 2004 for families in need of affordable housing in Calgary. This program not only provides us with a tangible result to our corporate giving, but also reinforces the spirit of teamwork at Enerplus as our employees will lend their manpower in the building of these homes.



Funds Flow from Operations reached record levels in 2003.



Due to strong commodity prices, our operating netback increased by 35% in 2003.

strength in numbers

Management's Discussion and Analysis ("MD&A")

The following discussion and analysis of financial results is dated March 10, 2004 and is to be read in conjunction with the audited consolidated financial statements as at and for the years ended December 31, 2003 and 2002. All amounts are stated in Canadian dollars unless otherwise specified. All references to notes are to those included with the consolidated financial statements. In accordance with Canadian practice, production volumes, reserve volumes and revenues are reported on a gross basis, before deduction of Crown and other royalties, unless otherwise indicated. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. Effective September 30, 2003, the Alberta Securities Commission implemented National Instrument 51-101 ("NI 51-101") *"Standards of Disclosure for Oil and Gas Activities"*. See recent Canadian accounting related pronouncements for further information.

Throughout the MD&A, we use the term funds flow from operations ("funds flow") and cash available for distribution. These terms as presented do not have any standardized meaning as prescribed by Canadian generally accepted accounting principles ("GAAP"), and therefore they may not be comparable with the calculation of similar measures for other entities. Funds flow as presented is not intended to represent operating cash flows or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with GAAP. All references to funds flow throughout this report are based on cash flow from operating activities before changes in non-cash working capital. Cash available for distribution is calculated using funds flow less cash withheld for acquisitions and capital expenditures.

2003 Overview

Successful acquisitions and development capital spending increased production, while high commodity prices, which were somewhat offset by the strengthening Canadian dollar, also helped to deliver positive returns for unitholders during 2003. Increased levels of activity within the oil and gas industry pushed costs higher throughout the year, while the positive impact associated with the internalization of the management contract should provide long term benefits to the Fund and unitholders.

Highlights

- Our unitholders realized a 55.4% total return in 2003 (representing the appreciation in unit price plus distributions paid during the year). This performance placed Enerplus third in a peer group of the eight largest conventional oil and gas trusts for 2003 and first on a three-year rolling basis for the second year in a row.
- Funds flow from operations, driven by strong oil and natural gas prices, increased 19% per trust unit.
- We paid $379.1 million to unitholders ($4.32 per trust unit) and retained $34.1 million ($0.39 per trust unit) for capital expenditures. This represented a payout ratio of 92% (81% before taking into account the internalization of the management contract as described below).
- Net income per trust unit increased 80% mainly due to higher commodity prices and production levels compared to 2002.
- We exceeded our annual production target for 2003 with average production volumes of 69,414 BOE/day despite an ongoing divestment program.
- Enerplus continued its active development program, investing $157.7 million in development drilling and facility enhancements. In 2003 we drilled 294 net wells with a 98% success rate.
- We spent $225.3 million acquiring oil and natural gas companies and properties during 2003. The Fund's finding, development and acquisition costs ("FD&A") for the year (using the new NI 51-101 standards) was $11.60 per BOE and $8.54 per BOE on a three-year basis.

- We disposed of $73.2 million in non-core properties during the year.
- Our recycle ratio (netback divided by FD&A) was 1.8 for 2003 and 1.9 on a three-year basis.
- Proved and probable reserves declined less than 1% compared to last year. Positive reserve additions from acquisition and development efforts were successful in replacing production and offsetting disposition activity for the year and negative revisions associated with NI 51–101.
- Enerplus had positive gross reserve revisions on a proved and probable basis of 1.3% or 4.0 million BOE. Positive revisions of 14.2 million BOE associated with our development activities more than offset negative revisions of 10.2 million BOE associated with NI 51-101. The majority of the NI 51–101 revisions were due to the new rule that disregards reserves extending beyond 50 years.
- Total gross proved reserves declined 13.6% compared to last year. Positive reserve additions from acquisitions and development were not sufficient to offset the negative effects of NI 51–101.
- Enerplus had negative reserve revisions on a proved basis of 10.7% or 31.0 million BOE. Positive reserve revisions of 10.9 million BOE from development activities were overshadowed by 41.9 million BOE in negative revisions associated with NI 51–101.
- Enerplus' Reserve Life Index ("RLI") continued to be one of the longest in the sector at 10.1 years on a proved basis and 13.3 years on a proved plus probable basis.
- On April 23, 2003 the Fund internalized its management contract by acquiring the management company from El Paso Corporation for $55.1 million.
- Operating costs increased 14.8% in 2003 to $6.73/BOE as a result of increased costs for labour, utilities and supplies along with an overall increase due to activity levels within the oil and gas industry.
- We chose to adopt the accounting standard for stock based compensation and recorded a non-cash charge of $1.4 million to general and administrative expenses.
- We completed two equity offerings in 2003, issuing 9.3 million trust units for gross proceeds of $307.8 million ($291.8 million net of costs).
- On October 1, 2003 we issued US$54 million of senior unsecured notes with a 12-year amortizing term and a coupon rate of 5.46% representing a rate that was 1% higher than the 10-year U.S. treasury bond rate at the time.
- On January 7, 2004 we closed the acquisition of Ice Energy Limited ("Ice Energy") for total consideration of approximately $132.2 million.
- We continue to maintain a conservative balance sheet as evidenced by a trailing net debt-to-funds flow ratio of 0.6x.

Results of Operations

Production

Daily production during 2003 averaged 69,414 BOE/day, an 11% increase over average production volumes of 62,784 BOE/day for 2002. This increase is primarily due to the acquisitions of Celsius Energy Resources Ltd. ("Celsius"), which closed October 21, 2002 and PCC Energy Inc. and PCC Energy Corp. (collectively "PCC"), which closed March 5, 2003.

Enerplus' production is widely distributed across more than 300 producing areas in Alberta, Saskatchewan and British Columbia. No single area accounts for more than 5% of total production. This diverse production base helps to reduce operating risks and provide more stable distributions over time.

Average production volumes for the years ended December 31, 2003 and 2002 are outlined below:

Daily Production Volumes	2003	2002	% Change
Natural gas (Mcf/day)	**240,907**	210,517	14%
Crude oil (bbls/day)	**24,597**	23,288	6%
Natural gas liquids (bbls/day)	**4,666**	4,410	6%
Total daily sales (BOE/day)	**69,414**	62,784	11%

Enerplus' exit production for the month of December 2003 averaged 69,300 BOE/day. This rate does not include production from the acquisition of Ice Energy, which closed January 7, 2004. Ice Energy produced approximately 2,300 BOE/day at that time.

Our current 2004 production is weighted 62% natural gas, 32% crude oil, and 6% natural gas liquids. We expect production for 2004 will average approximately 68,300 BOE/day. This estimate incorporates the Ice Energy acquisition, as well as production declines and forecast development capital expenditures throughout 2004, but is before the effects of any future acquisitions or dispositions.

Pricing and Price Risk Management

Our earnings, cash flow and financial condition are dependent on the prices we receive for our natural gas and crude oil production. Natural gas and crude oil prices have fluctuated widely during recent years.

The following table compares the Fund's average selling prices for 2003 with those of 2002. It also compares the benchmark price indices for the same periods.

Average Selling Price (Before the Effects of Hedging)	2003	2002	% Change
Natural gas (per Mcf)	**$ 6.30**	$ 3.87	63%
Crude oil (per bbl)	**36.15**	34.37	5%
Natural gas liquids (per bbl)	**33.43**	25.68	30%
Per BOE	**$ 36.94**	$ 27.49	34%

Average Benchmark Pricing	2003	2002	% Change
AECO natural gas (per Mcf)	**$ 6.70**	$ 4.07	65%
NYMEX natural gas (US$ per Mcf)	**5.54**	3.25	70%
WTI crude oil (US$ per bbl)	**31.04**	26.08	19%
WTI crude oil: C$ equivalent (C$/bbl)	**$ 43.11**	$ 40.75	6%
CDN$/US$ exchange rate	**$ 0.72**	$0.64	13%

At the outset of 2003, the AECO benchmark natural gas price was $6.46/Mcf. After an early start to winter and heavy draws on storage, prices increased to $10.14/Mcf in March. Gas prices fell back to $7.00/Mcf in the second quarter and remained above $6.00/Mcf for the balance of the summer. These strong summer prices were supported by concerns that storage could not be adequately filled for winter. By September, these concerns subsided and prices declined slightly to approximately $5.60/Mcf for the fourth quarter. Overall, AECO gas prices were 65% higher in 2003 compared to 2002.

As indicated by the current market for future prices (the "forward market"), AECO natural gas prices are expected to average $6.50/Mcf for 2004. Concerns remain that North American gas production may not keep pace with demand. The tight balance between supply and demand is expected to create volatility whenever there are unexpected changes to weather, storage or economic activity.

AECO Natural Gas Prices

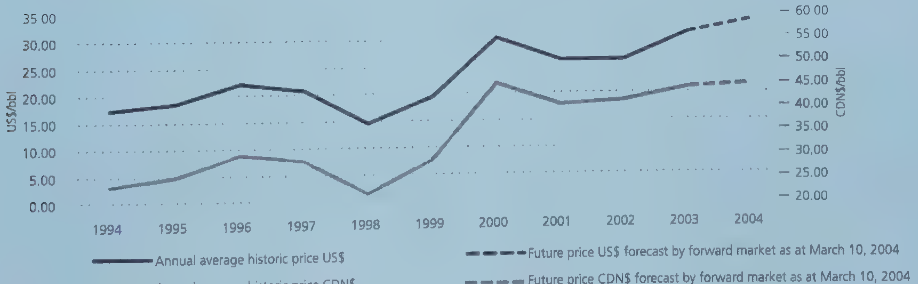
The crude oil benchmark West Texas Intermediate ("WTI") price entered 2003 at US$32.70/bbl. Hostilities in Iraq and cold winter weather pushed the price to levels as high as $36.00/bbl for the first quarter. Oil prices declined rapidly to the $28.00 to $30.00 range upon the resolution of the war in the second quarter. Despite earlier speculation of a further price collapse following the war, crude oil prices held these levels throughout the remainder of 2003. Iraq production was not restored as rapidly as expected, and crude and refined product inventories remained below normal levels. There were only three months in 2003 that the WTI crude oil price averaged less than US$30.00/bbl. Overall, WTI prices were 19% higher in 2003 compared to 2002.

The forward market currently predicts crude oil prices to average US$33.50/bbl for 2004. Increasing demand from China, Nigerian unrest, problems in Venezuela and OPEC talk of quota reductions are keeping upward pressure on the price of oil. Production is increasing from non-OPEC sources such as the former Soviet Union and offshore Africa, however the production response has not been enough to replenish inventory levels.

Unfortunately, the strengthening Canadian dollar against the U.S. dollar reduced prices received for the Fund's crude oil and a portion of its natural gas. Most of Canada's crude oil and natural gas is exported to the U.S. and is priced with reference to the U.S. dollar denominated benchmarks. The CDN$/US$ exchange rate entered 2003 at $0.65 and averaged $0.66 in the first quarter. After April, the Canadian dollar began to strengthen against its U.S. counterpart, mirroring the performance of the Euro and many other world currencies. By December the Canadian dollar was averaging $0.76. The U.S. faced challenges related to its weakening economy, high government debt and ongoing issues with respect to terrorism. Higher interest rates in Canada relative to the U.S. increased demand for the Canadian dollar. Overall, the Canadian dollar increased 13% in 2003. Although the WTI crude oil price increased 19% in 2003, the Canadian dollar equivalent price received by the Fund, after adjusting for the exchange rate, increased only 6%.

The current forward market predicts a CDN$/US$ exchange rate of $0.75 for 2004. Recent signs of economic strength in the U.S. and signs of economic weakness north of the border have stalled the rally in the Canadian dollar.

WTI Crude Prices



Enerplus maintains a commodity price risk management program. It is designed to provide price protection on a portion of our future production. Typically, a portion of the pricing upside is surrendered in return for protection against a significant downturn in prices. The program is intended to provide a measure of stability to our cash distributions and support towards realizing positive economic returns from our capital development and acquisition activities. We plan to continue this program in 2004. At the current time we do not have any CDN$/US$ exchange rate hedges associated with our revenues. However, we may consider hedging a portion of our foreign exchange exposure in the future.

As energy prices exceeded some of our hedged prices during 2003, we realized a cost of $45.8 million compared to an $8.7 million cost in 2002, as outlined below:

Cost from Financial Hedging ($ millions except per unit amounts)	2003		2002	
Crude oil	**$ 15.0**	**$ 1.67/bbl**	$ 4.3	$ 0.50/bbl
Natural gas	**30.8**	**$ 0.35/Mcf**	4.4	$ 0.06/Mcf
Net hedging cost	**$ 45.8**	**$ 1.81/BOE**	$ 8.7	$ 0.38/BOE

Enerplus' commodity risk management positions as at December 31, 2003 are described in Note 8. The fair value of the financial forward contracts at December 31, 2003 represented unrealized costs of $19.2 million on crude oil and $15.5 million on natural gas with reference to year-end prices and forward markets.

Enerplus has physical and financial contracts in place for the following production volumes:

Physical & Financial Price Risk Management	Contracted gas volumes (MMcf/day)	% of estimated gas production net of royalties	Contracted oil volumes (bbls/day)	% of estimated oil production net of royalties
First half of 2004	87	43	12,900	74
Second half of 2004	78	38	13,150	76
First half of 2005	57	28	7,500	43
Second half of 2005	54	27	4,500	26

We also fixed the cost of 5 megawatt hours ("MWh"), representing 30% of the power consumption by our Alberta operated properties at a price of $49.75/MWh for 2004. The fair value of this instrument at December 31, 2003 reflects an unrealized gain of $0.2 million.

Enerplus' risk management program will reduce, but not eliminate, the effects of changing prices and exchange rates. Our funds flow remains sensitive to changes as demonstrated by the following table:

Sensitivity to Changes in Price and Exchange Rate	Estimated Effect on 2004 Funds Flow per Trust Unit
Change of $0.10 per Mcf in the price of natural gas	$ 0.05
Change of US$1.00 per barrel in the price of WTI crude oil	$ 0.06
Change of 1,000 BOE/day in production	$ 0.05
Change of $0.01 in the US$/CDN$ exchange rate	$ 0.03
Change of 1% in interest rate	$ 0.03

These sensitivities reflect all commodity contracts as described in Note 8. They apply to commodity prices, production, interest and exchange rates within the context of current market rates. To the extent the market price of crude oil or natural gas change to levels that are above the ceiling or below the floor price limits set by existing commodity contracts, the above sensitivities will no longer be relevant.

Revenues

Crude oil and natural gas revenues after hedging were $890.0 million for 2003, which represents a 43% increase over revenues of $621.5 million for 2002. This was a result of higher production volumes and higher commodity prices. The increase was partially reduced by increased hedging costs as shown in the table below:

Analysis of Sales Revenues ($ millions)	Crude Oil	NGLs	Natural Gas	Total
2002 Sales Revenues	$ 287.9	$ 41.3	$ 292.3	$ 621.5
Price variance	16.0	13.2	214.7	243.9
Volume variance	16.4	2.4	42.9	61.7
Hedging variance	(10.7)	–	(26.4)	(37.1)
2003 Sales Revenues	**$ 309.6**	**$ 56.9**	**$ 523.5**	**$ 890.0**

Royalties

Royalties are paid to various government entities and other land and mineral rights owners. In 2003 royalties were $190.4 million compared to $131.8 million during 2002. The increase is due to higher production and commodity prices during 2003. Royalties, as a percentage of oil and gas sales before hedging, remained relatively constant between 2003 and 2002 at 20% and 21% respectively. Enerplus expects royalties to remain at approximately 20% in 2004.

Operating Expenses

Operating expenses for the year ended December 31, 2003 were $170.5 million or $6.73/BOE compared to $134.4 million or $5.86/BOE in 2002. Enerplus, along with most of the industry, experienced increased operating costs as a result of high levels of activity. In particular, we experienced increased costs for labour, utilities and supplies. As well, additional prior year charges on our partner-operated properties were recorded during the year, most notably during the fourth quarter. Given the costs experienced during 2003, we expect 2004 operating costs to be approximately $6.75/BOE.

General and Administrative Expenses

General and administrative ("G&A") expenses were $25.4 million or $1.00/BOE for the year ended December 31, 2003 compared to $16.0 million or $0.70/BOE for 2002. Compensation costs that included performance bonuses, an executive retention plan and the expensing of unit rights increased costs during 2003 compared to 2002. A portion of these costs arose as a result of the internalization of the management contract.

Included in compensation costs is $1.6 million related to a long-term executive incentive and retention plan called the Full Value Unit Plan ("FVUP"). The FVUP is based on the Fund's relative performance and total return over a three-year period compared to other senior conventional oil and gas trusts. The current performance periods of the plan end December 31, 2004 and December 31, 2005. No actual payments are required until one year after the performance periods.

We adopted the Canadian Institute of Chartered Accountants ("CICA") standard for expensing stock based compensation during 2003, and recorded a non-cash charge of $1.4 million or $0.05/BOE to G&A with respect to our trust unit rights incentive plan. This non-cash charge is based on the excess of the trust unit price over the exercise price of the rights at December 31, 2003 for rights granted in 2003 amortized over the vesting period. The trust unit price at December 31, 2003 was $39.35. Adoption of this standard had a negligible impact on net income and net income per unit in the previous three quarters.

The following table summarizes the cash and non-cash expenses recorded in G&A:

($ millions)	2003	2002
Cash	**$ 24.0**	$ 16.0
Trust units rights incentive plan (non-cash)	**1.4**	–
Total G&A	**$ 25.4**	$ 16.0

Pursuant to the full cost accounting guideline, we also capitalized $11.8 million of G&A costs in 2003 compared to $9.1 million in 2002. The majority of these capitalized costs represent charges for staff involved in development and acquisition activities.

Enerplus expects total G&A costs to be approximately $1.15/BOE during 2004. The forecasted increase reflects rising costs that are a result of high levels of industry activity and the increasing cost of compliance with recent regulatory requirements arising from the Sarbanes-Oxley Act and similar legislation in Canada. It also reflects increased staff levels and the recruitment of more specialized technical staff. This estimate assumes that non-cash charges for the trust unit rights plan will be similar to those experienced during 2003. The actual expense with respect to the trust unit rights plan and the FVUP in 2004 will be dependent on the performance of the Fund and the trust unit price throughout the year.

Management Fees and Internalization Expense

($ millions)	2003	2002
Base management fee	**$ 3.0**	$ 9.2
Performance fee	**–**	12.4
Total management fees	**$ 3.0**	$ 21.6

Effective April 23, 2003, all external management fees were eliminated with the purchase of Enerplus Global Energy Management Company ("EGEM") from an indirect subsidiary of El Paso Corporation ("El Paso"). Under the terms of the transaction, El Paso agreed to fix the management fees for the period January 1, 2003 to April 23, 2003 at an amount of $3.2 million. In addition, the amount recorded as management fee expense was reduced by $0.2 million to reflect the amortization of the note payable to EGEM as more fully described in Note 6.

We expensed all of the costs associated with the management internalization totaling $55.1 million during the second quarter of 2003. This treatment is in accordance with Emerging Issues Committee Abstract 138, *"Internalization of the Management Function in Royalty and Income Trusts"*, issued by the CICA.

Had we not completed this transaction, the management fees for 2003 would have been approximately $29.7 million. As a result, the internalization transaction represents an attractive pay-out of less than two years. Going forward, there will be no management or performance fees payable.

Interest Expense

Interest expense increased to $19.7 million in 2003 from $18.1 million in 2002. Higher average debt outstanding combined with higher average interest rates during 2003 resulted in the increase over 2002. At December 31, 2003, 43% of Enerplus' debt was based on fixed interest rates while 57% was floating. These instruments are more fully described in Note 3 and Note 8. During 2004 we anticipate interest rates to remain consistent with rates experienced during 2003.

Foreign Exchange

Enerplus incurred a $0.9 million foreign exchange gain in 2003 compared to a $0.2 million loss in 2002. The foreign exchange gain resulted primarily from translation of the US$54 million senior unsecured notes to the exchange rate in effect at December 31, 2003. This unrealized gain was partially offset by realized exchange losses on day-to-day transactions denominated in U.S. dollars. See Note 9.

Depletion, Depreciation and Amortization

Depletion, depreciation and amortization ("DD&A") of property, plant and equipment is recognized using the unit-of-production method based on proved reserves calculated in accordance with NI 51–101. Future costs for restoration and abandonment of well sites and facilities are estimated and amortized over the life of the properties on a unit-of-production basis as part of depletion, depreciation and amortization expense.

DD&A increased to $244.9 million or $9.67/BOE in 2003 from $213.9 million or $9.33/BOE in 2002. Higher production volumes during 2003 as well as revisions to reserves resulting from NI 51–101 have increased the total amount of DD&A expense. Proved reserves decreased approximately 13.6% under NI 51–101.

The Fund has prospectively adopted CICA Accounting Guideline 16 *"Oil and gas accounting—full cost."* Pursuant to the guideline, the Fund places a limit on the aggregate carrying value of property, plant and equipment (the "impairment test"). An impairment loss exists when the carrying amount of the Fund's property, plant and equipment exceeds the estimated undiscounted future net cash flows associated with the Fund's proved reserves. If an impairment loss is determined to exist, the costs carried on the balance sheet in excess of the discounted future net cash flows associated with the Fund's proved and probable reserves are charged to income.

No impairment existed at December 31, 2003 or January 1, 2003 using reserves determined under NI 51–101 and management's estimates of future prices. No impairment existed during 2002 under the previous Accounting Guideline 5. Our future price estimates are more fully discussed in Note 2.

Taxes

Capital taxes, consisting of the Federal Large Corporations Tax and the Saskatchewan Resource Surcharge, increased to $6.2 million in 2003 compared to $5.5 million in 2002. Commencing in 2004, the Federal Large Corporations Tax will be eliminated over the next five years, as a result of legislative changes. Given our current capital structure, capital taxes are expected to be $7.0 million in 2004.

Future income taxes arise from differences between the accounting and tax bases of the operating companies' assets and liabilities. In the Fund's structure, payments are made between the operating companies and the Fund, ultimately transferring both income and future income tax liability to the unitholders. Therefore, it is our opinion that no cash income taxes are expected to be paid by the operating companies in the future, and as such, the future income tax liability recorded on the balance sheet will be recovered through earnings over time.

For the year ended December 31, 2003, a future income tax recovery of $73.0 million was recorded in income compared to $35.4 million in 2002. The increased recovery in 2003 was mainly the result of legislative changes to reduce future income tax rates. Our expected future income tax rate incorporating these changes is approximately 35% compared to 42% as at December 31, 2002. Of the $73.0 million recovery, $35.8 million was attributed to the reduction in the future tax rate.

Annual Netbacks

Netbacks per BOE of Production	2003	2002
Production per day (BOE)	**69,414**	62,784
Weighted average sales price	**$ 36.94**	$ 27.49
Cost of oil and gas hedging	**(1.81)**	(0.38)
Net selling price	**35.13**	27.11
Royalties, net of ARTC	**(7.51)**	(5.75)
Operating costs	**(6.73)**	(5.86)
Operating netback	**20.89**	15.50
General and administrative	**(1.00)**	(0.70)
Non cash G&A expense (trust unit rights)	**0.05**	–
Management fees	**(0.12)**	(0.94)
Internalization of management contract	**(2.17)**	–
Interest expense, net of interest and other income	**(0.74)**	(0.77)
Foreign Exchange gain/(loss)	**0.04**	(0.01)
Non cash foreign exchange gain	**(0.12)**	–
Capital taxes	**(0.26)**	(0.23)
Restoration and abandonment cash costs	**(0.26)**	(0.20)
Funds flow from operations	**16.31**	12.65
Depletion and depreciation	**(9.43)**	(9.07)
Non cash G&A	**(0.05)**	–
Non cash foreign exchange	**0.12**	–
Amortization of site restoration, hedging and issue costs, net of cash costs	**0.02**	(0.06)
Future income tax recovery	**2.88**	1.54
Total net income per BOE after the effects of the internalization of the management contract	**$ 9.85**	$ 5.06
Total net income per BOE before the effects of the internalization of the management contract	**$ 12.02**	$ 5.06

Net Income and Funds Flow from Operations

Higher production volumes and more favourable commodity prices helped to increase oil and natural gas sales and net income for 2003 compared to 2002. These increases were somewhat offset by the one time management internalization costs of $55.1 million. The following table summarizes net income, funds flow from operations and other key measures for the last three years.

($ millions, except per unit amounts)	2003	2002	2001
Oil and gas sales (net of hedging)	**$ 890.0**	$ 621.5	$ 639.4
Net Income	**$ 249.6**	$ 115.9	$ 180.3
Per unit (Basic)	**$ 2.90**	$ 1.61	$ 3.28
Per unit (Diluted)	**$ 2.89**	$ 1.61	$ 3.28
Funds flow from operations	**$ 413.2**	$ 289.9	$ 340.2
Per unit (Basic)	**$ 4.79**	$ 4.03	$ 6.20
Cash available for distribution	**$ 379.1**	$ 246.8	$ 316.5
Per unit (Basic)	**$ 4.32**	$ 3.32	$ 5.67
Total assets	**$ 2,615.6**	$ 2,471.6	$ 2,284.3
Long-term debt, net of cash	**$ 257.7**	$ 361.0	$ 411.6

Quarterly Financial Information

Revenues, including the effects of hedging and the strengthening Canadian dollar, decreased each quarter in 2003 due to the gradual decline of realized prices on oil and gas sales. Net income for the fourth quarter of 2003 was negatively impacted as realized commodity prices were comparatively lower and additional operating and G&A costs were recorded.

($ millions, except per trust unit amounts)			Net income per trust unit	
	Net Revenues	Net Income	Basic	Diluted
2003				
First quarter	$ 199.4	$ 94.8	$ 1.14	$ 1.14
Second quarter	177.6	55.0	0.66	0.66
Third quarter	167.4	59.7	0.68	0.67
Fourth quarter	155.2	40.1	0.45	0.44
Total	$ 699.6	$ 249.6	$ 2.90	$ 2.89
2002				
First quarter	$ 97.0	$ 9.4	$ 0.13	$ 0.13
Second quarter	120.6	26.0	0.37	0.37
Third quarter	122.3	29.1	0.41	0.41
Fourth quarter	149.7	51.4	0.66	0.66
Total	$ 489.6	$ 115.9	$ 1.61	$ 1.61

Summary Fourth Quarter Information

Average daily production for the fourth quarter of 2003 was 69,841 BOE/day, an increase of 5% from the same period in 2002 due to the acquisition of PCC and a successful capital expenditure program. Operating expenses increased to $51.3 million or $7.98/BOE during the fourth quarter primarily due to prior year charges on partner operated properties. G&A expenses were $8.0 million or $1.25/BOE for the fourth quarter as charges for unit based compensation with respect to our trust unit rights incentive plan and additional performance based compensation costs were recorded.

	Three Months Ended December 2003	Three Months Ended December 2002	% Change
Daily Production Volumes			
Natural gas (Mcf/day)	243,573	228,480	7%
Crude oil (bbls/day)	24,477	23,795	3%
Natural gas liquids (bbls/day)	4,768	4,740	1%
Total daily sales (BOE/day)	69,841	66,615	5%
Average Selling Price (Before the Effects of Hedging)			
Natural gas (per Mcf)	$ 5.10	$ 4.99	2%
Crude oil (per bbl)	31.58	36.36	(13%)
Natural gas liquids (per bbl)	35.66	32.74	9%
Per BOE	$ 31.36	$ 32.44	(3%)
Operating Expenses ($ millions)	$ 51.3	$ 38.5	33%
Per BOE	$ 7.98	$ 6.29	27%
General and Administrative Expenses ($ millions)	$ 8.0	$ 6.0	33%
Per BOE	$ 1.25	$ 0.97	29%

Cash Available for Distribution

We make monthly cash distributions to our unitholders based upon the net cash flow from our oil and gas operations. A portion of this cash flow is typically withheld to fund a portion of our acquisition and development activities. For the year ended December 31, 2003, we generated $413.2 million in funds flow from operations. Of this amount (together with certain funds described in the following table), $379.1 million ($4.32 per trust unit) was paid to unitholders and $34.1 million ($0.39 per trust unit) was retained.

We monitor the distribution payout policy with respect to forecasted cash flows, debt levels and spending plans. The level of cash retained typically varies between 10% and 25% of annual cash flow, however we are prepared to adjust the payout levels in an effort to balance the investor's desire for distributions with the Fund's requirement to maintain a prudent capital structure.

The following table reconciles Enerplus' funds flow from operations with the cash available for distribution to unitholders.

Reconciliation of Cash Available for Distribution ($ millions, except per unit amounts)	2003	2002
Funds flow from operations before internalization of management contract	**$ 468.3**	$ 289.9
Management internalization costs	**(55.1)**	–
Funds flow from operations	**413.2**	289.9
Cash withheld for acquisition and development activities	**(34.1)**	(46.3)
Accruals (Note A)	**–**	3.2
Cash available for distribution (Note B)	**$ 379.1**	$ 246.8
Cash available for distribution per trust unit	**$ 4.32**	$ 3.32

Note A: According to the previous royalty agreement with Enerplus Resources Corporation ("ERC"), the royalty paid to the Fund was calculated on a cash basis. As a consequence, the change in the accrued net revenues of ERC for 2002 were added back to funds flow from operations for purposes of this reconciliation. Subsequent to December 31, 2002 the Fund amended the royalty agreement with ERC to allow for the royalty to be paid on an accrued basis.

Note B: The Consolidated Statement of Cash Flows reflects cash payments to unitholders during the calendar year. The cash available for distribution of $379.1 million in 2003 can be reconciled to the cash paid to unitholders of $372.6 million in the Consolidated Statement of Cash Flows by subtracting the February 2004 payments to unitholders and adding the February 2003 payments to unitholders.

Capital Expenditures

Enerplus spent $312.1 million on capital expenditures and acquisitions net of divestitures in 2003 compared to $361.7 million in 2002. Enerplus financed its capital expenditures through bank borrowing, new equity issues and by withholding a portion of cash otherwise available for distribution.

Capital Expenditures ($ millions)	2003	2002
Development expenditures	$ 115.6	$ 94.9
Plant and facilities	42.1	46.8
Sub-total	157.7	141.7
Office	2.3	4.4
Sub-total	160.0	146.1
Acquisitions of oil and gas properties	58.4	60.6
Corporate acquisitions	166.9	158.1
Dispositions of oil and gas properties	(73.2)	(3.1)
Total Net Capital Expenditures	$ 312.1	$ 361.7

As discussed in Note 7, our most significant acquisition during 2003 was PCC for $166.9 million. In addition, we purchased oil and gas properties at Joarcam, Hanna and Freda Lake for $58.4 million.

Capital Expenditures by Major Property ($ millions)	Development Type	2003	2002
Medicine Hat	Shallow gas	$ 11.6	$ 13.3
Deep Basin	Foothills gas	11.2	2.9
Bantry	Shallow gas	10.9	6.3
Countess	Shallow gas	7.3	–
Hanna Garden	Shallow gas	6.7	12.9
Progress	Oil waterflood	6.6	2.4
Verger	Shallow gas	5.3	6.0
Pembina 5 Way	Oil waterflood	4.6	5.9
Pine Creek	Natural Gas	4.4	0.7
Joslyn Creek	SAGD Oil	4.2	0.2
Other		84.9	91.1
Total		$157.7	$141.7

Total capital expenditures in 2004, including directly related administrative costs, are expected to be approximately $170 million. Of this amount, we expect to spend about $150 million on oil and natural gas drilling, facilities and development activities. This includes approximately $110 million for natural gas development most notably at Hanna Garden, Bantry, Shackleton, Verger, Medicine Hat and Deep Basin. In addition, we plan to initiate our natural gas from coal development opportunities at Joffre and Trochu. Oil development costs are expected to be approximately $35 million for 2004. The majority of these funds will be used to expand our facilities at Giltedge, Joarcam and Medicine Hat. We also plan to spend approximately $6 million to further develop our pilot project at Oil Sands Lease #24. Finally, land and seismic expenditures are expected to be approximately $4 million.

Enerplus routinely evaluates its property portfolio and disposes of non-core properties with limited contribution to cash flow or upside development potential. In 2003, we sold $73.2 million worth of non-core properties representing production of approximately 3,003 BOE/day. We expect to continue the process of acquiring new properties and rationalizing marginal properties in 2004.

Liquidity and Capital Resources

Long-term debt at December 31, 2003 was $338.1 million, representing $69.8 million and $268.3 million of Canadian dollar equivalent debt related to the US$54 million and US$175 million senior unsecured notes, respectively. Offsetting this debt was cash of $80.4 million, as the proceeds from the December equity issue were not fully deployed until Ice Energy was acquired on January 7, 2004. At December 31, 2003 long-term debt net of cash was $257.7 million. After giving effect to the Ice Energy acquisition, total debt outstanding was $389.9 million.

We have a conservative balance sheet as demonstrated below:

Financial Leverage and Coverage	Year ended December 31, 2003	Year ended December 31, 2002
Long-term debt to EBITDA	0.6 x	1.1 x
EBITDA to interest expense	22.6 x	17.5 x
Long-term debt to long-term debt plus equity	12%	19%

Long-term debt is measured net of cash.
We use EBITDA to determine the ability of the Fund to generate cash from operations. It is calculated from the consolidated statement of income as revenue less operating expenses, general and administrative expenses, management fees and internalization costs. This measure does not have any standardized meaning as prescribed by GAAP and may not be comparable to similar measures presented by other entities.

At year end, Enerplus' total borrowing base limit was $850 million consisting of senior unsecured notes of $341.1 million and bank facilities of $508.9 million. The bank facilities consist of a demand operating line of $31.7 million and a $477.2 million, 364 day revolving committed facility. We had $508.9 million of available borrowing capacity, and an additional $80.4 million in cash at year-end. After giving effect to the acquisition of Ice Energy on January 7, 2004 we had $457.1 million of available borrowing capacity.

In the event that the revolving bank line is not extended at the end of the 364-day revolving period, no principal payments are required during the first year of the term period. However, we would be required to maintain certain minimum balances on deposit with the syndicate agent. Principal payments on Enerplus' senior unsecured notes are required commencing in 2010 and 2011 and are more fully discussed in Note 3.

Payments with respect to the bank facilities, senior unsecured notes and other third party debt have priority over claims of and future distributions to the unitholders. Unitholders have no direct liability should cash flow be insufficient to repay this indebtedness. The agreements governing these bank facilities and senior unsecured notes stipulate that if we exceed certain borrowing thresholds, default, or fail to comply with certain covenants, the ability of the operating companies to make payments to the Fund and consequently the Fund's ability to make distributions to the unitholders may be restricted.

Our borrowing base is determined by the lenders' evaluation of the value of our proved oil and natural gas reserves. The lenders have reserved the right to revise the commitment based on an annual independent assessment of the Fund's year end reserve information and the lenders' commodity price outlook. Should the borrowing base be reduced below current outstanding debt levels, the Fund may need to obtain alternative financing, reduce distributions to unitholders, or dispose of properties.

We anticipate that we will continue to have adequate liquidity to fund future working capital and planned capital expenditures during 2004 through a combination of cash flow from operations and debt. Most of Enerplus' $170.0 million capital budget for 2004 is discretionary and can be revised downwards in the event of a significant commodity price downturn or similar economic event. We have historically demonstrated our ability to finance acquisitions and other future commitments through our debt facilities, distribution reinvestment plan and equity offerings.

Commitments

We have contracted to transport natural gas with various pipelines totaling 15 MMcf per day until 2008 and a further 5 MMcf per day until 2015. These transportation contracts will cost approximately $5.6 million in 2004.

Enerplus has an office lease commitment that extends to November 30, 2009. Annual costs of this lease commitment, which include rent and operating fees, amount to approximately $4.4 million. The Fund's commitments, contingencies and guarantees are more fully described in Note 10.

We must continue to pay Crown royalties, surface rentals, mineral taxes and abandonment and reclamation costs with respect to our ongoing ownership of hydrocarbon production rights. The amounts paid with respect to these burdens will depend on the future ownership, production, prices and legislative environment at the time.

Reserves producing approximately 33% of our current production are dedicated to certain aggregator sales arrangements. Under these arrangements, we receive a price based on the average netback price of the pool, net of transportation costs incurred by the aggregator for the life of the reserves.

Enerplus has the following minimum annual commitments including long-term debt:

($ thousands)	Total	Minimum Annual Commitment 2004 – 2007	2008	Total Committed after 2008
Senior Unsecured Notes	$ 338,117	$ –	$ –	$ 338,117
Pipeline Commitments	43,466	5,590	5,050	16,056
Office Lease	25,712	4,379	4,276	3,920
Total Commitments	**$407,295**	**$ 9,969**	**$ 9,326**	**$ 358,093**

Trust Unit Information

We had 94,349,000 trust units outstanding at December 31, 2003 compared to 82,898,000 trust units at December 31, 2002, reflecting the two equity offerings completed during the year. The weighted average basic number of trust units outstanding during 2003 was 86,202,000 (2002 – 71,946,000).

In addition to the equity offerings during 2003, 1,515,000 trust units (2002 – 626,000) were issued pursuant to the Trust Unit Monthly Distribution Reinvestment and Unit Purchase Plan ("DRIP") and the trust unit options and rights plans. This resulted in $40.4 million (2002 – $15.1 million) of additional equity to the Fund. A total of 660,000 units with a value of $21.4 million were issued to acquire corporate and property interests during 2003 compared to 31,000 units with a value of $0.7 million issued during 2002.

Income Taxes

The following sets out a general discussion of the Canadian and U.S. tax consequences of holding Enerplus trust units as capital property. The summary is not exhaustive in nature and is not intended to provide legal or tax advice. Investors or potential unitholders should consult their own legal or tax advisors as to their particular tax consequences.

Canadian Taxpayers

The Fund qualifies as a mutual fund trust under the Income Tax Act (Canada) and, accordingly, trust units of the Fund are qualified investments for RRSPs, RRIFs, RESPs, and DPSPs. Each year, the Fund is required to file an income tax return and any taxable income in the Fund is allocated to the unitholders.

In computing income, unitholders are required to include their pro-rata share of any taxable income earned by the Fund in that year. An investor's adjusted cost base ("ACB") in a trust unit equals the purchase price of the trust unit less any non-taxable cash distributions received from the date of acquisition. To the extent a unitholder's ACB is reduced below zero, such amount will be deemed to be a capital gain to the unitholder and the unitholder's ACB will be brought to $nil.

We paid $4.29 per trust unit in cash distributions to unitholders during the period February 2003 to January 2004. For Canadian tax purposes, 18% of these distributions, or $0.76 per trust unit was a tax deferred return of capital, 81% or $3.46 per trust unit was taxable to unitholders as other income, and 1% or $0.07 per trust unit was taxable dividend income.

For 2004, we estimate that 85% of cash distributions may be taxable and 15% may be a tax deferred return of capital. Actual taxable amounts may vary depending on actual distributions which are dependant upon production, commodity prices and funds flow experienced throughout the year.

U.S. Taxpayers

U.S. unitholders who receive cash distributions are subject to a 15% Canadian withholding tax, applied to the taxable portion of the distribution as computed under Canadian tax law. U.S. taxpayers may be eligible for a foreign tax credit with respect to Canadian withholding taxes paid.

The taxable portion of the cash distribution for U.S. tax purposes is determined by Enerplus in relation to its current and accumulated earnings and profits using U.S. income tax principles. The taxable portion determined is considered to be a dividend for U.S. tax purposes. For most U.S. taxpayers this should be a "Qualified Dividend" eligible for the reduced tax rate. We believe Enerplus should not be classified as a Passive Foreign Investment Company for U.S. income tax purposes for 2002 and 2003.

The non-taxable portion of the cash distribution, is a return of the cost (or other basis). The cost (or other basis) is reduced by this amount for computing any gain or loss arising from disposition. However, if the full amount of the cost (or other basis) has been recovered, any further non-taxable distributions should be reported as gains.

We paid US$3.04 per trust unit to U.S. residents during the 2003 calendar year, of which 13% or US$0.38 per trust unit was a tax deferred return of capital and 87% or US$2.66 per unit was a taxable dividend.

For 2004, we estimate that 85% of cash distributions may be taxable and 15% may be a tax deferred return of capital. Actual taxable amounts may vary depending on actual distributions which are dependant upon production, commodity prices and funds flow experienced throughout the year.

Critical Accounting Policies

The financial statements have been prepared in accordance with GAAP. A summary of significant accounting policies is presented in Note 1. A reconciliation of differences between Canadian and United States GAAP is presented in Note 12. Most accounting policies are mandated under GAAP and we do not have the ability to select alternatives. However, in accounting for oil and gas activities, we have a choice between two acceptable accounting policies: the full cost and the successful effort methods of accounting.

The Fund follows the full cost method of accounting for oil and natural gas activities. Using the full cost method of accounting, all costs of acquiring, exploring and developing oil and natural gas properties are capitalized, including unsuccessful drilling costs and administrative costs associated with acquisitions and development. Under the successful efforts method of accounting, all exploration costs, except costs associated with drilling successful exploration wells, are expensed in the period in which they are incurred. The difference between these two methodologies is not expected to be significant to the Fund's net income or net income per unit as the Fund participates in low risk development drilling that has traditionally achieved high success rates.

Under the Fund's full cost method of accounting, an impairment test is applied to the overall carrying value of property, plant and equipment, for a Canada-wide cost centre with the reserves valued using estimated future commodity prices at period end. Under the successful efforts method of accounting, the costs are aggregated on a property by property basis. The carrying value of each property is subject to an impairment test. Each policy may generate a different carrying value of property, plant and equipment and a different net income depending on the circumstances at period end.

Critical Accounting Estimates

The preparation of financial statements in accordance with GAAP requires management to make certain judgements and estimates. Changes in these judgements and estimates could have a material impact on our financial results and financial condition. The process of estimating reserves is critical to several accounting estimates. It requires significant judgements based on available geological, geophysical, engineering and economic data. These estimates may change substantially as data from ongoing development and production activities becomes available, and as economic conditions impacting oil and gas prices, operating costs and royalty burdens change. Reserve estimates impact net income through depletion, the determination of future site restoration and the application of an impairment test. The reserve estimates are also used to assess the borrowing base for the Fund's credit facilities. Revisions or changes in the reserve estimates can have either a positive or a negative impact on net income or the borrowing base.

Management's estimates of oil and natural gas prices in determining future cash flows are also critical as these prices are used in the cost centre impairment test. The carrying amount of property, plant and equipment as well as amounts recorded for depletion can be affected by the future price estimates.

Recent Canadian Accounting and Related Pronouncements

Standards of Disclosure for Oil and Gas Activities

Effective September 30, 2003, the Alberta Securities Commission implemented NI 51–101, "Standards of Disclosure for Oil and Gas Activities". NI 51–101 is effective for fiscal years that include or end December 31, 2003. The instrument imposes more standardized and more conservative guidelines for reserve estimates. Definitions for disclosure of reserves, net asset value, netbacks and finding and development costs are also provided in the instrument. We have adopted NI 51–101 at December 31, 2003, and as a result have realized a decrease in proved reserves and a minimal impact on proved plus probable reserves. Depletion expense increased for the year due to lower proved reserves, however there was no impact from the impairment test.

Continuous Disclosure Obligations

The Ontario Securities Commission has issued National Instrument 51–102 ("NI 51–102"), "Continuous Disclosure Obligations", effective for interim MD&A disclosures for the first quarter ending March 31, 2004. The instrument outlines enhanced requirements for disclosure in annual and interim financial statements, MD&A and the Annual Information Form ("AIF"). The instrument also proposes shorter reporting deadlines for annual and interim financial statements, MD&A and the AIF. We have substantially adopted NI 51–102 for the year ended December 31, 2003.

Full Cost Accounting Guideline

The Canadian Institute of Chartered Accountants ("CICA") issued Accounting Guideline 16, "Full Cost Accounting" for years beginning on or after January 1, 2004. The new guideline updates reserve definitions to include the standards of NI 51–101, sets criteria for accounting for disposals of properties and defines the method to be used to deplete and depreciate capitalized costs. The guideline also sets standards for presentation and disclosure under full-cost accounting. We have chosen early adoption of this guideline, prospectively, for the year ended December 31, 2003 to reflect the changes to oil and gas reserve measurement that have resulted from NI 51–101. Adoption of the guideline has not materially affected the Fund.

Unit Based Compensation

In September 2003, the CICA amended Handbook section 3870, "Stock Based Compensation and Other Stock Based Payments". The amendment requires that companies recognize an expense in the financial statements for stock based payments based on the fair value method beginning January 1, 2004. We have prospectively adopted this standard for the year ended December 31, 2003 in accordance with early adoption provisions. Enerplus used the intrinsic method to calculate this expense as certain features of the trust unit rights incentive plan prevented the use of traditional option pricing models. The trust unit rights incentive plan is described more completely in Note 1 and Note 3. Pursuant to the early adoption provisions, we were required to calculate and record an expense for any rights issued on or after January 1, 2003. The net income of the Fund decreased by $1.4 million as a result of adopting this standard.

Disclosure of Guarantees

The CICA issued Accounting Guideline 14, "Disclosure of Guarantees" in February 2003. This guideline requires disclosure of all guarantees, their fair value and a description of their nature in the notes to the financial statements. The new guideline is effective for fiscal years beginning on or after January 1, 2003. Adoption did not affect the financial results of the Fund for 2003.

Hedging Relationships

In November 2002, the CICA published an amended Accounting Guideline 13, "Hedging Relationships". The guideline establishes conditions where hedge accounting may be applied. It is effective for years beginning on or after July 1, 2003. The guideline will have an impact to the Fund's net income and net income per trust unit, as the 3-way option contracts for oil and natural gas as described in Note 7 will not qualify for hedge accounting. Where hedge accounting does not apply, any changes in the fair values of the option contracts relating to a period can either reduce or increase net income for that period. We expect to adopt this standard January 1, 2004. Had this standard been adopted for our 2003 fiscal year the impact would have reduced our net earnings by $1.5 million.

Asset Retirement Obligations

In December 2002, the CICA issued Handbook Section 3110, "Asset Retirement Obligations". This standard requires recognition of a liability representing the fair value of the future retirement obligations associated with property, plant and equipment. This fair value is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The standard is effective for all fiscal years beginning on or after January 1, 2004. We will adopt the standard January 1, 2004. Had this standard been adopted for our 2003 fiscal year the impact would have increased our net earnings by $0.7 million. Other accounting standards issued by the CICA during the year ended December 31, 2003 are not expected to materially impact the Fund.

Risk Factors and Risk Management

Enerplus investors are participating in the net cash flow from a portfolio of western Canadian crude oil and natural gas producing properties. As such, the cash flow paid to investors and the value of Enerplus units are subject to numerous risk factors. These risk factors, many of which are associated with the oil and gas industry, include, but are not limited to, the following influences:

Commodity Price Risk

Enerplus' operating results and financial condition are dependent on the prices that it receives for its crude oil and natural gas production. These prices may fluctuate widely in response to a variety of factors including global and domestic economic conditions, weather conditions, the supply and price of imported oil and liquefied natural gas, the production and storage levels of North American natural gas, political stability, transportation facilities, the price and availability of alternative fuels and government regulations.

We use financial derivative instruments and other hedging mechanisms to help limit the adverse effects of natural gas and oil price volatility. However, we do not hedge all of our production, and expect there will always be a portion that remains unhedged. Furthermore, we use financial instruments such as collars and three-way options that offer only limited protection within selected price ranges. To the extent price exposure is hedged, we may forego the benefits that would otherwise be experienced if commodity prices increase.

Operational Risk and Cost Control

The value of Enerplus trust units is based on the underlying value of the oil and gas reserves. Geological and operational risks can affect the quantity and quality of reserves and the cost of ultimately recovering those reserves. Lower oil and natural gas prices may increase the risk of write-downs of our oil and gas property investments. As activity levels in the industry increase, upward pressure is placed on administrative and operating costs. Higher costs will decrease the amount of cash flow received by the Fund and therefore, reduce distributions to unitholders.

We strive to acquire low risk, mature properties with a high proportion of proven reserves, high cash netbacks, long reserve lives and predictable production. Similarly, we generally participate in lower-risk development projects, while farming out or monetizing higher risk exploratory prospects.

Each year, a firm of independent engineers evaluates a significant portion of our proved and probable reserves. At December 31, 2003 approximately 86% of the reserves, comprised of our larger properties, were evaluated. The remaining minor properties were evaluated internally and reviewed by the independent engineers. The Reserves Committee of the Board of Directors has reviewed and approved the reserve report of the independent evaluators.

We strive to control costs through incentive-based compensation plans that reward employees for cost control and value-added initiatives. We attempt to minimize costs by exploiting our purchasing strength with suppliers. In 2004, Enerplus fixed the price on a portion of its Alberta electrical consumption. We use detailed budgeting and accounting practices to monitor costs. Multi-functional teams regularly perform integrated field reviews designed to reduce costs and increase revenues from our properties.

Despite these efforts, it can be difficult to control costs in the oil and gas industry, especially in periods of high commodity prices when the demand for goods and services is strong. Oil and gas production involves a significant amount of fixed costs that are difficult to reduce without decreasing production. In addition, approximately 40% of Enerplus' production is operated by third parties. We have limited ability to influence costs on partner-operated properties.

Reserve Risk

Oil and natural gas reserves naturally deplete as they are produced over time. Our ability to replace production depends on our success in acquiring new reserves and developing existing reserves. Acquisitions of oil and gas assets depend on Enerplus' assessment of value at the time of acquisition. Incorrect assessments of value can adversely affect distributions to unitholders and the value of the trust units.

Acquisitions are subject to investment guidelines, due diligence and review. Major acquisitions are approved by the Board of Directors and where appropriate, independent reservoir engineer evaluations are obtained. Enerplus has a diversified asset base that helps to limit the potential for a significant negative event.

Access to Capital Markets

Since Enerplus distributes the majority of its net cash flow to unitholders, we must finance a large portion of our acquisition and development activity through continued access to the equity and debt capital markets. As such, we are dependent on continued access to the capital markets to fund our activities directed towards maintaining and increasing value for our unitholders.

Enerplus has listings on the Toronto and New York stock exchanges and maintains an active investor relations program.

We maintain a prudent capital structure by retaining a portion of cash flow for capital spending and utilizing the equity markets when deemed appropriate.

Continued access to capital is dependant on our ability to maintain our track record of performance and to demonstrate the advantages of the acquisition or development program that we are financing at the time.

Non-Resident Ownership and Mutual Fund Trust Status

Since our listing on the New York Stock Exchange in November of 2000, we have seen increased trading volumes and levels of ownership by non-residents of Canada. Based on information received from our transfer agent and financial intermediaries in February 2004, an estimated 64% of outstanding trust units are held by non-residents. However, this estimate may not be accurate as it is based on certain assumptions and data from the security industry that does not have a well-defined methodology to determine the residency of beneficial holders of securities.

As a result of the current structure and assets of the Fund, Enerplus meets the requirements of an exception in the Income Tax Act (Canada) (the "Tax Act"), which would otherwise require a mutual fund trust not to be maintained primarily for the benefit of non-residents of Canada. Our trust indenture does not have a specific limit on the percentage of trust units that may be owned by non-residents.

As with other legislation or regulations affecting the Fund, there can be no assurance that the provisions of the Tax Act will be maintained in their current form, or if changed, how any transitional provisions may affect the Fund.

At this time, management does not anticipate any legislative changes that would affect our status as a mutual fund trust, however, we have implemented provisions in our trust indenture to allow the Board of Directors to adopt non-resident ownership constraints if required in order to ensure Enerplus maintains its mutual fund trust status.

Environmental and Safety Risk ("E&S")

Environmental, health and safety risks influence our workforce as well as operating and capital costs. In addition, our industry is subject to numerous E&S laws and regulations.

Enerplus mitigates these risks by:

- *Developing and adhering to standards, procedures and practices that protect the environment and the health and safety of our employees, contractors and the public, while meeting or exceeding government regulations and requirements.*
- *Requiring field employees and contractors to attend regular meetings and training programs to review health and safety regulations and workplace standards and procedures.*
- *Regularly conducting health and safety inspections and audits to ensure hazards are identified and controlled.*
- *Reviewing all safety incidents in order to prevent reoccurrence and raise safety awareness.*
- *Conducting environment inspections to ensure environmental liabilities are identified and corrected using Enerplus' well site and facility reclamation and abandonment program.*
- *Ensuring emergency response plans that meet all regulatory requirements are in place and practiced regularly to prevent and deal with incidents quickly and effectively.*

Interest Rate Exposure

The Fund has exposure to movements in interest rates. Changing interest rates can affect borrowing costs and the trust unit price of yield-based investments such as Enerplus.

We monitor the interest rate forward market and have fixed the interest rate on approximately 43% of our debt through fixed rate senior unsecured notes and through interest rate swaps for terms of up to 3 years.

Foreign Currency Exposure

Enerplus has exposure to fluctuations in foreign currency as a result of the issuance of senior unsecured notes denominated in US dollars.

We have hedged our foreign currency exposure on US$175 million of senior unsecured notes using financial swaps that convert the US denominated debt to Canadian dollar debt with Canadian dollar interest obligations. We have not hedged our foreign exchange exposure with respect to the US$54 million of senior unsecured notes issued in October 2003 which have US dollar interest payment obligations.

Enerplus also has indirect exposure to fluctuations in foreign currency as crude oil sales and a portion of natural gas sales are based on US dollar indices. Our oil and gas revenues benefit from a weak Canadian dollar relative to the US dollar.

We have not entered into any foreign currency hedges with respect to oil and natural gas sales. However, we are monitoring exchange rates, and may consider entering into hedging arrangements to reduce the impact of volatility in the exchange rate on a portion of our US dollar sales exposure in the future.

Counterparty Risk

We assume customer credit risk associated with oil and gas sales, financial hedging transactions and joint venture participants.

We have established credit policies and controls designed to mitigate the risk of default or nonpayment with respect to oil and gas sales, financial hedging transactions and joint venture participants. Enerplus maintains a diversified sales customer base and we review our single-entity exposure on a regular basis.

Regulatory Risk

Government royalties, income tax laws, environmental laws and regulatory requirements can have a significant financial and operational impact on Enerplus. As an oil and gas producer, we are subject to a broad range of regulatory requirements. Similarly, as a mutual fund trust, Enerplus has a unique structure that is vulnerable to changes in legislation or income tax law.

Although we have no control over these regulatory risks, we continuously monitor changes in these areas through such activities as participating in industry organizations and conferences, exchange of information with third party experts and employing qualified individuals to assess the impact of such changes on the Fund's financial and operating results.

Unitholder Liability

The law is uncertain on the question of whether unitholders could be held personally liable for the indebtedness of the Fund. The Ontario government has introduced a bill to provide statutory protection for unitholders similar to the protection afforded shareholders in a corporation. This legislation has not yet been passed and there is no guarantee the other provincial jurisdictions will enact similar statutory protection.

We mitigate this risk by conducting all of our active business through the Fund's corporate subsidiaries. We limit the Fund to a narrow range of activities associated with the receipt of net cash flow from these operating corporations.

Business Prospects

Enerplus offers investors the benefits of owning a large, diversified portfolio of oil and natural gas properties without the exploration risks commonly associated with traditional exploration and production ("E&P") companies. As such, our business prospects are closely linked to the opportunities and challenges associated with oil and natural gas production. In particular, Enerplus is strongly influenced by the price of crude oil and natural gas, both of which have been volatile in recent years.

In 2003, we delivered a 55.4% total return to unitholders through unit appreciation and monthly cash distributions. Over the last three years, we have delivered a 43.5% total return to our unitholders. Looking forward to 2004, our business plan features some of the same strategies that have supported our 18-year track record of success:

Growth

- Replace production through a disciplined acquisitions strategy;
- Focus on acquisitions where Enerplus has a competitive advantage;
- Focus on larger acquisitions to avoid the competition for smaller packages;
- Acquire properties with predictable production profiles, long reserve lives, high cash netbacks and opportunities for low risk development;
- Consider diversification into other energy-related investments such as processing facilities;
- Maintain a portfolio of future development opportunities within existing properties;
- Maintain a work environment that attracts and retains qualified professionals;

Portfolio Optimization

- Develop core competencies and focus our asset base where we have a competitive technical or operating advantage;
- Utilize technologies and expertise to optimize the performance of existing properties through low-risk development, production enhancements and cost management;
- Dispose of marginal non-core properties at attractive valuations;

Risk Management

- Hedge oil and natural gas prices on a portion of future production to provide protection in the event of adverse price movements;
- Hedge a portion of future electrical costs;
- Focus on low-risk development;

Corporate Governance

- Apply high standards of corporate governance and ethics;
- Apply standards and practices that protect the environment and the health and safety of our employees.

Financing

- Utilize debt conservatively;
- Diversify credit sources and payment terms;
- Hedge interest rates associated with a portion of long-term debt;
- Withhold 10% to 25% of cash flow from operations to contribute towards annual development expenditures;
- Issue equity for acquisitions and growth opportunities in a manner that adds value to existing unitholders.

Summary 2004 Outlook

In recent years, our unitholders have enjoyed the benefits of a number of positive macro-economic trends, including:

- Increasing prices for crude oil and natural gas;
- Low interest rates fueling a demand for yield-based investments;
- An active acquisition market for oil & gas properties;
- A structural advantage when competing with E&P companies for acquisitions; and,
- Until recently, a limited number of trusts were competing for these acquisitions.

Enerplus' strategy is to maintain our discipline and flexibility to take advantage of opportunities, even if some of these macro-economic trends temporarily turn negative for the sector.

The following chart summarizes Enerplus' 2004 outlook provided throughout this MD&A. We do not attempt to forecast commodity prices, and as a result, we do not forecast future cash distributions to unitholders. Readers are encouraged to apply their own price expectations to the following factors to arrive at an expected cash distribution.

Summary of 2004 Expectations	Target	Comments
Average annual production	68,300 BOE/day	Assumes no new acquisitions/dispositions
Royalty rate	20%	Percentage of gross unhedged sales
Operating expenses	$6.75/BOE	
G&A costs	$1.15/BOE	Includes unit rights plan and FVUP
Management fees	NIL	Eliminated with internalization transaction in 2003
Capital taxes	$7 million	Based on current capital structure
Average interest cost	4.0%	Based on current fixed rates and forward market
Cash flow pay-out ratio	75 – 90%	
Development capital spending	$170 million	Based on current plans and price environment
DRIP equity issuance	$20 million	
Oil & gas price hedging	continuing	See Note 8 to the financial statements for a list of current hedge positions

Additional Information

Additional information relating to Enerplus Resources Fund, including the Fund's Annual Information Form, is available under the Fund's profile on the SEDAR website at www.sedar.com

Forward-Looking Statements

This discussion and analysis contains forward-looking statements relating to future events or future performance. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expects", "projects", "plans", "anticipates" and similar expressions. These statements represent management's expectations or beliefs concerning, among other things, future operating results and various components thereof or the economic performance of Enerplus. Undue reliance should not be placed on these forward-looking statements which are based upon management's assumptions and are subject to known and unknown risks and uncertainties, including the business risks discussed above, which may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Accordingly, readers are cautioned that events or circumstances could cause results to differ materially from those predicted. Enerplus undertakes no obligation to update publicly or revise any forward-looking statements contained herein and such statements are expressly qualified by the cautionary statement.

Management's Responsibility for Financial Statements

In management's opinion, the accompanying consolidated financial statements of Enerplus Resources Fund (the "Fund") have been prepared within reasonable limits of materiality and in accordance with Canadian generally accepted accounting principles. Since a precise determination of many assets and liabilities is dependent on future events, the preparation of financial statements necessarily involves the use of estimates and approximations. These have been made using careful judgement and with all information available up to March 10, 2004. Management is responsible for all information in the annual report and for the consistency, therewith, of all other financial and operating data presented in this report.

To meet its responsibility for reliable and accurate financial statements, management has established and monitors systems of internal control which are designed to provide reasonable assurance that financial information is relevant, reliable and accurate, and that assets are safeguarded and transactions are executed in accordance with management's authorization.

The consolidated financial statements have been examined by Deloitte & Touche LLP, independent Chartered Accountants. Their responsibility is to express a professional opinion on the fair presentation of the consolidated financial statements in accordance with Canadian generally accepted accounting principles. The Auditors' Report outlines the scope of their examination and sets forth their opinion.

The Audit Committee, consisting exclusively of independent directors, has reviewed these statements with management and the external auditors and has recommended their approval to the Board of Directors. The Board of Directors has approved the consolidated financial statements of the Fund.

Gordon J. Kerr
President and
Chief Executive Officer

Robert J. Waters
Senior Vice President and
Chief Financial Officer

R J Waters

Calgary, Alberta
March 10, 2004

Auditors' Report

To the Unitholders of Enerplus Resources Fund:

We have audited the consolidated balance sheets of Enerplus Resources Fund (the "Fund") as at December 31, 2003 and 2002 and the consolidated statements of income, accumulated income, accumulated cash distributions and cash flows for the years then ended. These financial statements are the responsibility of the Fund's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Fund as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

DELOITTE & TOUCHE LLP
Chartered Accountants

Deloitte & Touche LLP

Calgary, Alberta
March 5, 2004

Consolidated Balance Sheets

as at December 31 ($ thousands)	2003	2002
Assets		
Current assets		
Cash	$ 80,416	$ 718
Accounts receivable	71,304	92,986
Other current	13,412	1,975
	165,132	95,679
Property, plant and equipment (Note 2)	2,448,365	2,374,145
Deferred charges (Note 3)	2,115	1,807
	$2,615,612	$2,471,631
Liabilities		
Current liabilities		
Accounts payable	$ 100,449	$ 79,189
Distributions payable to unitholders	33,022	24,870
Payable to related party (Note 6)	–	19,038
	133,471	123,097
Long-term debt (Note 3)	338,117	361,729
Future income taxes (Note 5)	268,515	340,269
Accumulated site restoration	60,335	59,038
Deferred credits	1,942	4,266
Payable to related party (Note 6)	–	1,400
	668,909	766,702
Equity		
Unitholders' capital (Note 4)	2,511,375	2,156,999
Accumulated income	690,046	440,446
Accumulated cash distributions	(1,388,189)	(1,015,613)
	1,813,232	1,581,832
	$2,615,612	$2,471,631

Signed on behalf of the Board of Directors:

Douglas R. Martin
Director

Robert L. Normand
Director

Consolidated Statements of Income

for the year ended December 31 ($ thousands except per trust unit amounts)	2003	2002
Revenues		
Oil and gas sales	$935,819	$630,167
Hedging costs	(45,808)	(8,717)
Royalties	(190,395)	(131,837)
	699,616	489,613
Interest and other income	913	559
	700,529	490,172
Expenses		
Operating	170,476	134,387
General and administrative (Note 4)	25,369	16,039
Management fees (Note 6)	3,042	21,576
Management internalization (Note 6)	55,100	–
Interest on long-term debt (Note 3)	19,708	18,100
Foreign exchange (gain)/loss (Note 9)	(924)	187
Depletion, depreciation and amortization	244,890	213,908
	517,661	404,197
Income before taxes	182,868	85,975
Capital taxes	6,223	5,483
Future income tax recovery (Note 5)	(72,955)	(35,384)
Net Income	$249,600	$115,876
Net income per trust unit		
Basic	$ 2.90	$ 1.61
Diluted	$ 2.89	$ 1.61
Weighted average number of trust units outstanding (thousands)		
Basic	86,202	71,946
Diluted	86,501	72,084

Consolidated Statements of Accumulated Income

for the year ended December 31 ($ thousands)	2003	2002
Accumulated income, beginning of year	$440,446	$324,570
Net income	249,600	115,876
Accumulated income, end of year	$690,046	$440,446

Consolidated Statements of Cash Flows

for the year ended December 31 ($ thousands)	2003	2002
Operating Activities		
Net income	$ 249,600	$ 115,876
Depletion, depreciation and amortization	244,890	213,908
Non cash foreign exchange gain (Note 9)	(3,003)	–
Unit based compensation (Note 4)	1,364	–
Future income tax recovery	(72,955)	(35,384)
Site restoration and abandonment costs incurred	(6,696)	(4,548)
Funds flow from operations	413,200	289,852
Decrease in non-cash working capital	14,234	15,162
	427,434	305,014
Financing Activities		
Issue of trust units, net of issue costs (Note 4)	331,595	329,752
Cash distributions to unitholders	(372,576)	(237,621)
Decrease in bank credit facilities	(93,401)	(319,188)
Issuance of senior unsecured notes	72,792	268,328
Payment to related party	(1,400)	(509)
Debt issue costs (Note 3)	(475)	(1,892)
Increase in non-cash financing working capital	8,152	4,010
	(55,313)	42,880
Investing Activities		
Capital expenditures	(159,994)	(146,116)
Property acquisitions	(36,954)	(60,581)
Property dispositions	73,214	3,058
Corporate acquisitions (Note 7)	(165,815)	(161,403)
Decrease (increase) in non-cash investing working capital	(2,874)	16,887
	(292,423)	(348,155)
Change in cash	79,698	(261)
Cash, beginning of year	718	979
Cash, end of year	$ 80,416	$ 718
Supplementary Cash Flow Information		
Cash income taxes paid	$ –	$ –
Cash interest paid	$ 18,584	$ 17,740

Consolidated Statements of Accumulated Cash Distributions

for year ended December 31 ($ thousands)	2003	2002
Accumulated cash distributions, beginning of year	$ 1,015,613	$ 777,992
Cash distributions to unitholders	372,576	237,621
Accumulated cash distributions, end of year	$ 1,388,189	$ 1,015,613

1. Summary of Significant Accounting Policies

The management of Enerplus Resources Fund ("Enerplus" or the "Fund") prepares the financial statements in accordance with Canadian generally accepted accounting principles ("GAAP"). A reconciliation between Canadian GAAP and United States GAAP is disclosed in Note 12. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The following significant accounting policies are presented to assist the reader in evaluating these consolidated financial statements and, together with the following notes, should be considered an integral part of the consolidated financial statements.

(a) Organization and Basis of Accounting

The Fund is an open-end investment trust created under the laws of the Province of Alberta operating pursuant to the Amended and Restated Trust Indenture between EnerMark Inc., its wholly-owned subsidiary, Enerplus Resources Corporation ("ERC") and CIBC Mellon Trust Company as Trustee. The beneficiaries of the Fund (the "unitholders") are holders of the trust units issued by the Fund. As a trust under the Income Tax Act (Canada), Enerplus is limited to holding and administering permitted investments and making distributions to the unitholders.

The Fund's financial statements include the accounts of the Fund and its subsidiaries on a consolidated basis. All inter-entity transactions have been eliminated.

(b) Revenue Recognition

Revenue associated with the sale of crude oil, natural gas and natural gas liquids is recognized when title passes from the Fund to its customers. A portion of the properties acquired through the acquisition of PCC Energy Inc. and PCC Energy Corp. (collectively, "PCC") are subject to a royalty arrangement with a private company that is structured as a net profits interest. Results from the operations of PCC, after reduction for this net profits interest, have been included in the Fund's consolidated financial statements subsequent to March 5, 2003.

(c) Property, Plant and Equipment ("PP&E")

The Fund follows the full cost method of accounting for petroleum and natural gas properties under which all acquisition and development costs are capitalized. Such costs include land acquisition, geological, geophysical and drilling costs for productive and non-productive wells and directly related overhead charges. Repairs, maintenance and operational costs that do not extend the recoverable reserves are charged to earnings. Proceeds from the sale of petroleum and natural gas properties are applied against capitalized costs. Gains and losses are not recognized upon disposition of oil and natural gas properties unless such a disposition would alter the rate of depletion by 20% or more.

(d) Impairment Test

The Fund has prospectively adopted CICA Accounting Guideline 16 *"Oil and gas accounting—full cost"*, ("AcG–16"). Pursuant to AcG–16, the Fund places a limit on the aggregate carrying value of PP&E (the "impairment test"). An impairment loss exists when the carrying amount of the Fund's PP&E exceeds the estimated undiscounted future net cash flows associated with the Fund's proved reserves. If an impairment loss is determined to exist, the costs carried on the balance sheet in excess of the discounted future net cash flows associated with the Fund's proved and probable reserves are charged to income. Reserves are determined pursuant to NI 51–101. The adoption of this guideline had no impact on the financial statements.

(e) Depletion and Depreciation ("DD&A")

The provision for depletion and depreciation of oil and natural gas assets is calculated using the unit-of-production method based on the Fund's share of estimated proved reserves before royalties. Reserves and production are converted to equivalent units on the basis of 6 Mcf = 1 bbl reflecting the approximate relative energy content.

(f) Site Restoration and Abandonment

The provision for estimated site restoration costs is determined using the unit-of-production method and is included in depletion, depreciation and amortization expense ("DD&A"). Actual site restoration costs are charged against the accumulated liability.

(g) Income Taxes

The Fund is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the Fund's unitholders. As the Fund distributes all of its taxable income to the unitholders and meets the requirements of the Income Tax Act (Canada) applicable to the Fund, no provision for income tax has been made by the Fund, except for its subsidiaries as noted below.

The Fund follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements of the Fund's corporate subsidiaries and their respective tax bases, using substantively enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs.

(h) Financial Instruments

The Fund is exposed to market risks resulting from fluctuations in commodity prices and interest rates in the normal course of operations. The Fund uses various types of financial instruments to manage these market risks. Proceeds and costs realized from holding crude oil and natural gas contracts are recognized in oil and gas revenues at the time each transaction under a contract is settled. The costs or proceeds realized from holding interest rate swaps are recognized in interest expense at the time each transaction is settled.

(i) Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at the balance sheet date. Revenues and expenses are translated at the monthly average rates of exchange. Translation gains and losses are included in income in the period in which they arise.

(j) Accounting for Unit Based Compensation

Effective for the fiscal years beginning on or after January 1, 2003, the Fund prospectively adopted CICA Handbook section 3870, *"Stock based compensation"*, which applies to trust unit rights granted on or after that date. It is not possible to determine a fair value for the unit rights using traditional option pricing models as the exercise price of rights granted under the plan may be reduced in future periods. The amount of the reduction cannot be reasonably estimated as it is dependent upon a number of factors including, but not limited to, future commodity prices received, future production levels and amounts to be withheld for debt repayment, capital expenditures and acquisitions. As a result, the Fund measures unit compensation expense based on the intrinsic value of the rights and recognizes the amount in income over the vesting period. After the rights have vested, changes in the intrinsic value are recognized to income in the period of change. The intrinsic value is determined to be the excess of the trust unit price over the exercise price of the right at the date of exercise, or the date of the financial statements for unexercised rights. The change in value is reflected in general and administrative expenses ("G&A") and contributed surplus. The cash received upon exercise of the rights is credited to unitholders' capital. Rights granted prior to January 1, 2003 are not included in unit based compensation expense as the Fund discloses the pro forma results based on the intrinsic value of these awards over their vesting period.

(k) Disclosure of Guarantees

The Fund adopted CICA Accounting Guideline 14 *"Disclosure of Guarantees"*. Pursuant to the guideline the Fund has disclosed all material guarantees issued to third parties.

2. Property, Plant and Equipment

($ thousands)	2003	2002
Property, plant and equipment	**$ 3,384,572**	$ 3,071,298
Accumulated depletion and depreciation	**(936,207)**	(697,153)
Net property, plant and equipment	**$ 2,448,365**	$ 2,374,145

Included in the depletion and depreciation calculation are future capital costs of $180,700,000 (2002 – $203,410,000) and capitalized G&A of $11,847,000 (2002 – $9,109,000).

An impairment test calculation was performed on the Fund's PP&E at December 31, 2003 in which the estimated undiscounted future net cash flows associated with the proved reserves exceeded the carrying amount of the Fund's PP&E. A similar test performed at January 1, 2003 upon adoption of AcG–16 also resulted in a surplus. Further, no impairment would have been recognized at December 31, 2003 under the prior accounting policy.

The following table outlines benchmark prices used in the impairment test at December 31, 2003:

Year	WTI Crude Oil[1] US$/bbl	Exchange Rate US$/CDN$	Edm Light Crude[1] CDN$/bbl	AECO Natural Gas[1] CDN$/Mcf
2004	$ 29.63	0.75	$ 37.99	$ 5.81
2005	26.80	0.75	34.24	5.15
2006	25.76	0.75	32.87	4.59
2007	26.14	0.75	33.37	4.71
2008	26.53	0.75	33.87	4.80
Thereafter (inflation %)	1.5%	0%	1.5%	1.5%

[1] Actual prices used in the impairment test were adjusted for commodity price differentials specific to the Fund.

3. Long-Term Debt

($ thousands)	2003	2002
Bank credit facilities (a)	**$ –**	$ 93,401
Senior unsecured notes (b)	**338,117**	268,328
Total long-term debt	**$ 338,117**	$ 361,729

(a) Bank Credit Facilities

On May 31, 2003, the Fund's borrowing base was increased to $850,000,000. At year-end, Enerplus had bank facilities of $508,880,000 available under two facilities consisting of a demand operating line of credit of $31,672,000 and a $477,208,000, 364 day revolving committed facility with an incremental two-year term. Various borrowing options are available under the facility including prime rate based advances and banker's acceptance loans.

In the event that the revolving bank line is not extended at the end of the 364 day revolving period, no principal payments are required during the first year of the term period. However, Enerplus will be required to maintain certain minimum balances on deposit with the syndicate agent.

Since a demand for payment with respect to the operating facility would be financed by the revolving facility, no portion of the operating facility has been classified as current.

(b) Senior Unsecured Notes

On October 1, 2003 Enerplus issued US$54,000,000 senior unsecured notes that mature October 1, 2015. The notes have a coupon rate of 5.46% priced at par with interest paid semi-annually on April 1 and October 1 of each year. Principal payments are required in five equal installments beginning October 1, 2011 and ending October 1, 2015. Costs incurred in connection with issuing the notes in the amount of $475,000 are classified as deferred charges on the balance sheet and are being amortized to DD&A over the term of the notes. As at December 31, 2003, the amount remaining to be amortized associated with these costs was $465,000. The notes are subject to fluctuations in foreign exchange rates. At December 31, 2003 the notes were carried at $69,789,000 with the resulting $3,003,000 gain on translation of foreign debt being included in the determination of net income for the year.

On June 19, 2002 Enerplus issued US$175,000,000 senior unsecured notes that mature June 19, 2014. The notes have a coupon rate of 6.62% priced at par, with interest paid semi-annually on June 19 and December 19 of each year. Principal payments are required in five equal installments beginning June 19, 2010 and ending June 19, 2014. Costs incurred in connection with issuing the notes in the amount of $1,892,000 are classified as deferred charges on the balance sheet and are being amortized to DD&A over the term of the notes. As at December 31, 2003, the amount remaining to be amortized was $1,650,000 (2002 - $1,807,000). Concurrent with the issuance of the notes on June 19, 2002, the Fund entered into a cross currency swap with a syndicate of financial institutions. Under the terms of the swap, the amount of the notes was fixed for purposes of interest and principal repayments at a notional amount of CDN$268,328,000. Interest payments are made on a floating rate basis, set at the rate for three-month Canadian banker's acceptances, plus 1.18%.

The bank credit facilities and the senior unsecured notes (the "Combined Facilities") are the legal obligation of EnerMark Inc. and are guaranteed by its subsidiaries. Payments with respect to the Combined Facilities have priority over payments to the Fund and over claims of and future distributions to the unitholders. However, unitholders have no direct liability should cash flow be insufficient to repay the Combined Facilities.

4. Fund Capital

(a) Unitholders' Capital

Trust Units

Authorized: Unlimited number of trust units

(thousands) Issued:	2003 Units	2003 Amount	2002 Units	2002 Amount
Balance, beginning of year	**82,898**	**$ 2,156,999**	69,532	$ 1,826,507
Redemption of units	**(24)**	**(590)**	–	–
Issued for cash:				
Pursuant to public offerings	**9,300**	**291,791**	12,709	314,624
Pursuant to option and rights plans	**893**	**21,438**	140	2,844
Distribution Reinvestment and Unit Purchase Plan	**622**	**18,956**	486	12,284
Issued for acquisition of corporate and property interests	**660**	**21,417**	31	740
	94,349	**2,510,011**	82,898	2,156,999
Contributed Surplus (Trust Unit Rights Plan)	**–**	**1,364**	–	–
Balance, end of year	**94,349**	**$ 2,511,375**	82,898	$ 2,156,999

On December 17, 2003, Enerplus completed an equity offering of 4,400,000 trust units at a price of $35.65 per trust unit for gross proceeds of $156,860,000 ($148,717,000 net of issuance costs).

On July 17, 2003, Enerplus completed an equity offering of 4,900,000 trust units at a price of $30.80 per trust unit for gross proceeds of $150,920,000 ($143,074,000 net of issuance costs).

On November 29, 2002, Enerplus completed an equity offering of 7,959,300 trust units at a price of $26.00 per trust unit for gross proceeds of $206,942,000 ($193,738,000 net of issuance costs).

On September 12, 2002, Enerplus completed an equity offering of 4,750,000 trust units at a price of $26.85 per trust unit for gross proceeds of $127,538,000 ($120,886,000 net of issuance costs).

Pursuant to the monthly Distribution Reinvestment and Unit Purchase Plan ("DRIP"), Canadian unitholders are entitled to reinvest cash distributions in additional trust units of the Fund. Trust units are issued at 95% of the weighted average market price on the Toronto Stock Exchange for the twenty trading days preceding a distribution payment date without service charges or brokerage fees. Eligible unitholders are also entitled to make optional cash payments to acquire additional trust units, however the 5% discount does not apply. During 2003, $18,956,000 (2002 – $12,284,000) was raised pursuant to the DRIP.

Trust units are redeemable at any time, on demand by unitholders, at 85% of the current market price. Redemptions cannot exceed $500,000 during any calendar month. During 2003, 24,000 units were redeemed at a cost of $590,000 to the Fund. No units were redeemed during 2002.

(b) Trust Unit Rights Incentive Plan

As at December 31, 2003, a total of 2,192,000 rights pursuant to the Trust Unit Rights Incentive Plan ("Rights Plan") at an average exercise price of $30.05 were outstanding. This represents 2.3% of the total trust units outstanding of which 430,000 rights with an average exercise price of $24.03 were exercisable. Under the Rights Plan, distributions per trust unit to Enerplus unitholders in a calendar quarter which represent a return of more than 2.5% of the net PP&E of Enerplus at the end of such calendar quarter may result in a reduction in the exercise price of the rights. Results for the year ended December 31, 2003, reduced the exercise price of the outstanding rights by $1.47 per trust unit of which a $0.39 reduction is effective January 2004 and a $0.39 reduction is effective April 2004.

Activity for the rights issued pursuant to the Rights Plan is as follows:

	2003		2002	
	Number Of Rights (000's)	**Weighted Average Exercise Price[1]**	Number Of Rights (000's)	Weighted Average Exercise Price[1]
Trust Unit Rights outstanding				
Beginning of year	**2,028**	**$ 25.11**	1,318	$ 24.50
Granted	**1,124**	**35.56**	873	26.18
Exercised	**(776)**	**24.30**	(22)	24.31
Cancelled	**(184)**	**25.39**	(141)	24.44
End of year	**2,192**	**30.05**	2,028	25.11
Rights exercisable at the end of the year	**430**	**$ 24.03**	571	$ 24.31

[1] Exercise price reflects grant prices less reduction in strike price discussed above.

The following table summarizes information with respect to outstanding Unit Rights as at December 31, 2003:

Rights Outstanding at December 31, 2003 (000's)	Original Exercise Price	Exercise Price after Price Reductions	Expiry Date December 31	Rights Exercisable December 31, 2003 (000's)
429	$ 24.50	$ 23.28	2007	264
10	25.45	24.35	2008	1
26	26.40	25.30	2008	3
35	27.33	26.30	2008	5
585	26.09	25.20	2008	157
135	27.70	27.01	2009	–
144	33.00	32.62	2009	–
110	36.00	36.00	2009	–
718	37.62	37.62	2009	–
2,192	$ 30.63	$ 30.05		430

In accordance with the early adoption provision of the CICA Handbook Section 3870, non-cash compensation costs of $1,364,000 ($0.02 per unit) related to the rights issued during 2003 have been charged to general and administrative expense during 2003.

The following table outlines the estimated compensation cost associated with the rights issued during 2002 and the pro forma effects on net income and net income per unit.

($ thousands, except per unit amounts)	2003	2002
Net income as reported	**$ 249,600**	$ 115,876
Compensation expense for rights issued in 2002	**(5,425)**	(181)
Pro forma net income	**$ 244,175**	$ 115,695
Net income per trust unit – basic		
Reported	**$ 2.90**	$ 1.61
Pro forma	**$ 2.83**	$ 1.61
Net income per trust unit – diluted		
Reported	**$ 2.89**	$ 1.61
Pro forma	**$ 2.82**	$ 1.61

(c) Trust Unit Option Plan

As at December 31, 2003, 4,000 options pursuant to the Trust Unit Option Plan were outstanding and exercisable. These options are exercisable at an average price of $22.90 and expire December 31, 2004. During the year ended December 31, 2003, 117,000 options were exercised at a weighted average price of $22.03 and 2,000 options were cancelled at a weighted average price of $22.90. No new options have been granted under the Trust Unit Option Plan since December 31, 2000 as this plan was superseded by the Rights Plan discussed above.

5. Income Taxes

(a) Enerplus Resources Fund

The Fund is an inter-vivos trust for income tax purposes. As such, the Fund's income that is not allocated to the Fund's unitholders is taxable. The Fund intends to allocate all taxable income to unitholders.

For 2003, the Fund had taxable income of $307,000,000 (2002 – $157,100,000) or $3.53 per trust unit (2002 – $2.15 per trust unit). Taxable income of the Fund is comprised of dividend, royalty and interest income, less deductions for Canadian oil and gas property expense ("COGPE") and issue costs.

The amounts of COGPE and issue costs remaining in the Fund at December 31, 2003 are $370,681,000 and $29,381,000 respectively (2002 – $355,456,000 and $22,608,000).

(b) Corporate Subsidiaries

The future income tax liability on the balance sheet arises as a result of the following temporary differences:

($ thousands)	2003	2002
Excess of net book value of property, plant and equipment over the underlying tax bases	$ 289,496	$ 358,058
Future site restoration deductions	(20,981)	(18,584)
Other	–	795
Future income tax liability	$ 268,515	$ 340,269

The provision for income taxes varies from the amounts that would be computed by applying the combined Canadian federal and provincial income tax rates for the following reasons:

($ thousands)	2003	2002
Income before taxes	$ 182,868	$ 85,975
Computed income tax expense at the enacted rate of 40.75% (42.12% for 2002)	$ 74,519	$ 36,213
Increase (decrease) resulting from:		
Effect of change in tax rate	(35,800)	(1,668)
Net income attributed to the Fund	(117,812)	(65,803)
Non-deductible crown royalties and other payments	43,359	30,962
Federal resource allowance	(42,682)	(24,135)
Alberta royalty tax credit	(204)	(311)
Management internalization	19,601	–
Adjustment related to prior acquisitions	(12,863)	(10,642)
Other	(1,073)	–
Future income tax recovery	$ (72,955)	$ (35,384)

6. Related Party Transactions

On April 23, 2003, the Fund internalized its management contract for total cash consideration of $55,100,000. The amount was expensed during the second quarter of 2003, and consisted of a cash payment of $48,898,000 to acquire the outstanding common shares of Enerplus Global Energy Management Company ("EGEM") from an indirect subsidiary of El Paso Corporation ("El Paso"). Retention bonuses of $4,700,000 and additional costs of $1,502,000 were also included as part of the internalization expense.

Prior to the internalization transaction the Fund paid management fees to EGEM. The management fees consisted of a base fee which represented 2.75% of net operating income and a performance fee that was based on the total return and relative performance of the Fund compared to other senior conventional oil and gas trusts. During 2002, management fees totaled $21,576,000. In conjunction with the internalization transaction management fees for the period January 1, 2003 to April 23, 2003 were fixed at $3,200,000. All management fees have been eliminated subsequent to the internalization transaction.

Pursuant to a share purchase agreement dated June 21, 2001, the Fund acquired all of the outstanding common shares of ERC from EGEM. Consideration for the shares was $2,545,000 which was payable over five years as a reduction in management fees. This reduction in management fees amounted to $158,000 for the period January 1, 2003 to April 23, 2003. The remaining payable balance was eliminated as a result of the internalization transaction.

In prior years, Enerplus had entered into financial instrument contracts at market rates with an indirect subsidiary of El Paso. These contracts expired during the fourth quarter of 2003.

7. Corporate Acquisitions

The fair values of the assets acquired and liabilities assumed for the following acquisitions are summarized as follows:

($ thousands)	2003 PCC	2002 Celsius
Property, plant and equipment	**$ 168,123**	$ 200,156
Future income taxes	**(1,201)**	(42,093)
	166,922	158,063
Cash	**8,846**	–
Non cash working capital	**(9,953)**	3,340
Net assets acquired	**$ 165,815**	$ 161,403

(a) PCC Energy Inc. and PCC Energy Corp. ("PCC")

On March 5, 2003, the Fund acquired all of the outstanding shares of PCC, for total cash consideration of $165,815,000 including related costs. Available lines of credit financed the acquisition, which has been accounted for using the purchase method of accounting for business combinations. Results from operations subsequent to March 5, 2003 are included in the Fund's consolidated financial statements.

(b) Celsius Energy Resources Ltd.

On October 21, 2002, the Fund acquired all the outstanding common shares and retired the debt of Celsius Energy Resources Ltd. ("Celsius"), for consideration of $161,403,000, which was comprised of $160,950,000 in cash and related costs of $453,000. Available lines of credit financed the acquisition, which has been accounted for using the purchase method of accounting for business combinations. Results from operations subsequent to October 21, 2002 are included in the Fund's consolidated financial statements.

8. Financial Instruments

The Fund's financial instruments represented in the balance sheet consist of cash, accounts receivable, other current assets, current liabilities, deferred credits and long-term debt.

The carrying value of cash, accounts receivable and current liabilities approximate their fair value. Other current assets are comprised of prepaid expenses and marketable securities. The marketable securities are carried on the balance sheet at the lower of cost and fair value. The fair value at December 31, 2003 of $16,369,000 exceeded the cost of these securities. The Fund carried US$54,000,000 of fixed rate debt. In addition, it carried US$175,000,000 of fixed rate debt that was converted to CDN$268,328,000 floating rate debt. At December 31, 2003 the fair value of these instruments were $72,006,000 and $242,813,000 respectively. See Note 3 and Note 9.

These estimated values have been determined based on available market information and appropriate valuation methods. The actual amounts realized may differ from these estimates.

(a) Credit Risk

Most of the Fund's accounts receivable relate to oil and natural gas sales and are exposed to typical industry credit risks. The Fund manages this credit risk by entering into sales contracts with only highly rated entities and reviewing its exposure to single entities on a regular basis. The Fund is also exposed to certain losses in the event of non-performance by counterparties to derivative financial instruments. This credit risk is managed by the Fund by selecting financially sound counterparties.

(b) Derivative Financial Instruments

The Fund uses certain derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. The fair values of these instruments are based on an approximation of the amounts that would have been paid to or received from counterparties to settle the instruments outstanding as at December 31, 2003 with reference to forward prices and market valuations provided by independent sources.

The fair values of derivative financial instruments are as follows:

Interest Rate and Cross Currency Swaps

In addition to the cross currency swap described in Note 3, the Fund has entered into interest rate swaps on $75,000,000 of notional debt at rates varying from 3.74% to 4.70% before banking fees that are expected to range between 0.85% and 1.05%. The maturity date of these interest rate swaps were extended by a year to June 2006 during the second quarter of 2003. The fair value value of the $75,000,000 interest rate swaps as at December 31, 2003 represents an unrealized cost of $1,813,000.

The fair value of the cross currency swap related to the US$175,000,000 senior unsecured notes as at December 31, 2003 represents an unrealized cost of $25,053,000.

Crude Oil Instruments

Enerplus has entered into the following financial option contracts to reduce the impact of a downward movement in crude oil prices. The fair value of the financial crude oil contracts outstanding as at December 31, 2003 reflects an unrealized cost of $19,177,000.

The following table summarizes the Fund's crude oil risk management positions:

		WTI US$/bbl		
	Daily Volumes Bbls/day	Sold Call	Purchased Put	Sold Put
Term				
Jan. 1, 2004 – Sep. 30, 2004				
3-way option	1,500	$ 29.00	$ 22.00	$ 19.25
3-way option	1,500	$ 30.00	$ 23.00	$ 20.00
Jan. 1, 2004 – Jun. 30, 2004				
3-way option	1,500	$ 28.00	$ 22.50	$ 19.60
3-way option	500	$ 28.00	$ 22.50	$ 19.90
Jan. 1, 2004 – Dec. 31, 2004				
3-way option	1,500	$ 29.50	$ 22.00	$ 20.00
3-way option	1,000	$ 28.10	$ 23.00	$ 20.50
3-way option	1,000	$ 28.50	$ 25.00	$ 22.00
3-way option	1,400	$ 28.00	$ 23.00	$ 19.50
3-way option	1,500	$ 29.25	$ 25.00	$ 22.00
Jul. 1, 2004 – Jun. 30, 2005				
3-way option	1,500	$ 28.00	$ 24.00	$ 21.00
Jul. 1, 2004 – Sep. 30, 2005				
3-way option	1,500	$ 29.50	$ 24.50	$ 21.50
Oct. 1, 2004 – Sep. 30, 2005				
3-way option	1,500	$ 29.40	$ 24.50	$ 21.50
Jan. 1, 2004 – Dec. 31, 2005				
3-way option[1]	1,500	$ 30.00	$ 27.23	$ 23.00
Jan. 1, 2005 – Dec. 31, 2005				
3-way option[1]	1,500	$ 30.00	$ 25.35	$ 22.00

[1] Financial option transactions entered into during the fourth quarter of 2003.

Natural Gas Instruments

Enerplus has the following physical and financial contracts in place on its natural gas production as described below. The fair value of the financial natural gas contracts as at December 31, 2003 reflects an unrealized cost of $15,549,000.

The following table summarizes the Fund's natural gas risk management positions:

		AECO$/Mcf CDN$				
	Daily Volumes MMcf/day	Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps	Escalated Price
Term						
Jan. 1, 2004 – Jun. 30, 2004						
3-way option	9.5	$ 7.39	$ 4.75	$ 3.17	–	–
Jan. 1, 2004 – Sep. 30, 2004						
3-way option	9.5	$ 6.67	$ 4.75	$ 3.17	–	–
3-way option	9.5	$ 7.39	$ 4.75	$ 3.69	–	–
Jan. 1, 2004 – Oct. 31, 2004						
Swap	3.8	–	–	–	$ 2.90	–
Jan. 1, 2004 – Dec. 31, 2004						
3-way option	9.5	$ 7.91	$ 5.80	$ 4.22	–	–
3-way option(1)	9.5	$ 7.72	$ 5.81	$ 4.75	–	–
Swap	2.8	–	–	–	$ 5.51	–
Jan. 1, 2004 – Jun. 30, 2005						
3-way option	2.8	$ 7.12	$ 5.69	$ 4.75	–	–
Apr. 1, 2004 – Oct. 31, 2004						
3-way option(2)	9.5	$ 6.86	$ 5.81	$ 4.75	–	–
Jul. 1, 2004 – Dec. 31, 2005						
3-way option(1)	9.5	$ 6.65	$ 5.61	$ 4.75	–	–
Jan. 1, 2005 – Dec. 31, 2005						
3-way option(1)	9.5	$ 6.60	$ 5.65	$ 4.75	–	–
3-way option(1)	9.5	$ 6.86	$ 5.81	$ 4.75	–	–
Jan. 1, 2004 – Oct. 31, 2006						
Swap	9.5	–	–	–	$ 5.47	–
Swap	4.8	–	–	–	$ 5.25	–
Swap	4.8	–	–	–	$ 5.24	–
Swap	4.8	–	–	–	$ 5.28	–
2004 – 2010						
Physical	2.0	–	–	–	–	$ 2.52

(1) Financial option transactions entered into during the fourth quarter of 2003.

(2) Financial option transaction entered into subsequent to December 31, 2003 that is not included in the fair value.

Electricity Instrument

During the fourth quarter of 2003, the Fund entered into an electricity swap contract that fixed the price of electricity on 5MW/hr of Alberta Power Pool electricity consumption at $49.75/MWh from January 1, 2004 to December 31, 2004. The fair value of this instrument as at December 31, 2003 reflects an unrealized gain of $165,000.

9. Foreign Exchange

($ thousands)	2003	2002
Unrealized foreign exchange gain on translation of US dollar denominated senior notes	**$ (3,003)**	$ –
Realized foreign exchange losses	**2,079**	187
Foreign exchange (gain)/loss	**$ (924)**	$187

The US$54,000,000 senior unsecured notes that are exposed to foreign currency fluctuations are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Foreign exchange gains and losses are included in the determination of net income for the period.

10. Commitments and Contingencies

(a) Pipeline Transportation

Enerplus has contracted to transport natural gas with various pipelines totaling 15 MMcf per day until 2008 and a further 5 MMcf per day until 2015.

(b) Oil Sands Lease #24

During 2002, the Fund acquired a 16% working interest in the Oil Sands Lease #24 (Joslyn Creek Lease). The acquisition included the assumption of approximately $4,333,000 in contingent project debt that was comprised of $3,360,000 of principal and approximately $973,000 in accrued interest at December 31, 2003. Interest is accrued at the Bank of Canada prime business rate and is not compounded. The debt is contingent on both production and pricing hurdles with respect to development on the lease. As it is too early in the development of this project to determine if these hurdles will be satisfied, the contingent debt has not been accrued in the consolidated financial statements.

(c) Office Lease

Enerplus has an office lease commitment that extends to November 30, 2009. Annual costs of this lease commitment, which include rent and operating fees, amount to approximately $4,379,000.

(d) Guarantee

Subsequent to December 31, 2003, Enerplus entered into a guarantee for a maximum of $1,000,000 in its capacity as a partner in a limited partnership, which was established for the purpose of marketing natural gas. At December 31, 2003 there were no obligations associated with this guarantee.

Enerplus has the following minimum annual commitments including long-term debt:

($ thousands)	Total	Minimum Annual Commitment 2004 – 2007	2008	Total Committed after 2008
Senior unsecured notes	$ 338,117	$ –	$ –	$ 338,117
Pipeline commitments	43,466	5,590	5,050	16,056
Office lease	25,712	4,379	4,276	3,920
Total commitments	$ 407,295	$ 9,969	$ 9,326	$ 358,093

11. Event Subsequent to December 31, 2003

Subsequent to December 31, 2003, the Fund acquired all of the issued and outstanding shares of Ice Energy Limited for total consideration of approximately $132,200,000. The acquisition closed January 7, 2004 and will be accounted for using the purchase method of accounting for business combinations. The purchase price allocation has not yet been determined.

12. Differences Between Canadian and United States Generally Accepted Acounting Principles

The Fund's consolidated financial statements have been prepared in accordance with Canadian GAAP. These principles, as they pertain to the Fund's consolidated statements, differ from United States GAAP ("U.S. GAAP") as follows:

The application of U.S. GAAP would have the following effects on net income as reported:

($ thousands)	2003	2002
Net income as reported in the Consolidated Statement of Income – Canadian GAAP	$ 249,600	$ 115,876
Adjustments		
Depletion, depreciation, amortization and accretion (Notes (a) and (f))	91,118	83,511
Compensation expense (Note (b))	(12,400)	(3,406)
Unrealized gain (loss) on financial derivatives (Note (d))	4,733	(25,312)
Income before cumulative effect of change in accounting principle – U.S. GAAP	333,051	170,669
Total income tax expense, including expense due to change in tax rates of $37,312 for 2003	70,741	21,285
Net income before cumulative effect of change in accounting principle – U.S. GAAP	262,310	149,384
Cumulative effective of change in asset retirement obligation accounting principle, net of income taxes of $13,305 (Note (f))	29,023	–
Net income after cumulative effect of change in accounting principle – U.S. GAAP	291,333	149,384
Net unrealized gain (loss) on hedging instruments, net of tax recovery of $20,266 and tax recovery due to change in tax rates of $1,450 for 2003 (Note (e))	(36,840)	10,415
Comprehensive income	$ 254,493	$ 159,799
Net income per trust unit before cumulative change in accounting principle		
Basic	$ 3.04	$ 2.08
Diluted	$ 3.03	$ 2.07
Effect of cumulative change in accounting principle		
Basic	$ 0.34	–
Diluted	$ 0.34	–
Net income per trust unit after cumulative change in accounting principle		
Basic	$ 3.38	$ 2.08
Diluted	$ 3.37	$ 2.07
Weighted average number of trust units outstanding		
Basic	86,202	71,946
Diluted	86,501	72,084
Accumulated income		
Balance, beginning of year – U.S. GAAP	$ (168,164)	$ (317,548)
Net income	291,333	149,384
Balance, end of year – U.S. GAAP	$ 123,169	$ (168,164)
Accumulated other comprehensive income		
Balance, beginning of year	$ 10,415	$ –
Net unrealized gain (loss) on hedging instruments, net of tax	(36,840)	10,415
Balance, end of year	$ (26,425)	$ 10,415

The application of U.S. GAAP would have the following effects on the balance sheet as reported:

($ thousands)	Canadian GAAP	Increase (decrease)	U.S. GAAP
December 31, 2003			
Property, plant and equipment, net	$ 2,448,365	$ (798,052)	$ 1,650,313
Financial derivative liabilities	–	61,427	61,427
Accumulated site restoration/Asset retirement obligation	60,335	3,601	63,936
Future income taxes/Deferred income taxes	268,515	(315,211)	(46,696)
Unitholders' capital	2,510,011	29,626	2,539,637
Contributed surplus	1,364	15,806	17,170
Accumulated income	690,046	(566,877)	123,169
Accumulated other comprehensive income	–	(26,425)	(26,425)
December 31, 2002			
Financial derivative assets	$ –	$ 37,100	$ 37,100
Property, plant and equipment, net	2,374,145	(935,099)	1,439,046
Financial derivative liabilities	–	44,704	44,704
Future income taxes	340,269	(377,541)	(37,272)
Unitholders' capital	2,156,999	29,626	2,186,625
Contributed surplus	–	3,406	3,406
Accumulated income	440,446	(608,610)	(168,164)
Accumulated other comprehensive income	–	10,415	10,415

(a) Under U.S. GAAP full cost accounting, the carrying value of petroleum and natural gas properties and related facilities, net of deferred income taxes, is limited to the present value of after tax future net revenue from proven reserves, discounted at 10% (based on prices and costs at the balance sheet date), plus the lower of cost and fair value of unproven properties. Under Canadian GAAP, an impairment loss exists when the carrying amount of the Fund's PP&E exceeds the estimated undiscounted future net cash flows associated with the Fund's proved reserves. If an impairment loss is determined to exist, the costs carried on the balance sheet in excess of the discounted future net cash flows associated with the Fund's proved and probable reserves are charged to income. The application of the impairment test under U.S. GAAP did not result in a write-down of capitalized costs in either 2003 or 2002.

Where the amount of an impairment test write-down under Canadian GAAP differs from the amount of the write-down under U.S. GAAP, the charge for depletion, depreciation, amortization and accretion will differ in subsequent years. Historical write-downs for U.S. GAAP have resulted in depletion, depreciation, amortization and accretion being $90,037,000 ($58,623,000 net of tax) lower than for Canadian GAAP for the year ended December 31, 2003. The difference for the year ended December 31, 2002 was an $83,511,000 ($51,443,000 net of tax) reduction in the amount of depletion, depreciation, amortization and accretion recorded.

(b) The Financial Accounting Standards Board's ("FASB") Statement of Financial Standards ("SFAS") 123, *"Accounting for Stock-based Compensation"*, establishes financial accounting and reporting standards for stock-based employee compensation plans. As the exercise price of the Trust Unit Rights are subject to downward revisions from time to time, the Rights Plan is a variable compensation plan under U.S. GAAP. Accordingly, compensation expense is determined as the excess of the market price over the exercise price at the end of each reporting period and is deferred and recognized in income over the vesting period of the rights. In 2003, the Fund voluntarily changed to the fair value method of accounting for unit based compensation under SFAS 123 for alll unit right grants and grant modifications after January 1, 2003 using the prospective method described in SFAS 148. This change in accounting policy does not impact the accounting treatment for the Rights Plan as it is a variable compensation plan.

As a result of adoption of fair value accounting under both U.S. GAAP and Canadian GAAP the only remaining difference is that for Canadian GAAP no compensation expense is recorded for rights issued prior to January 1, 2003.

Unit based compensation for the year ended December 31, 2003 on all rights issued was $13,764,000 (2002 – $3,406,000). The charge to net income for Canadian GAAP was $1,364,000 for the year ended December 31, 2003, resulting in a GAAP difference of $12,400,000.

(c) Enerplus has prospectively adopted SFAS 123 for the Unit Option Plan using the prospective method described in SFAS 148. For all options granted prior to January 1, 2003, the Fund applies Accounting Principles Board Opinion No. 25, *"Accounting for Stock Issued to Employees"*, whereby no compensation expense is recognized for options granted with an exercise price equal to the market value of the units on the date of the grant.

No compensation expense has been recorded for Canadian GAAP in relation to the Unit Option Plan and as no options were issued in 2003 under the Unit Option Plan, no compensation expense has been included in income for the Unit Option Plan for U.S. GAAP. Had compensation cost for Enerplus Unit Options granted prior to January 1, 2003 been determined based on the fair value at the grant dates of the awards consistent with the methodology prescribed by SFAS 123, Enerplus' net income and net income per unit for years ended December 31, 2003 and 2002 would have been the pro forma amounts indicated below:

($ thousands, except per unit amounts)	2003	2002
Net income under U.S. GAAP		
As reported	$ 291,333	$ 149,384
Compensation costs under fair value method	(32)	(525)
Pro forma	291,301	148,859
Net income per trust unit under U.S. GAAP		
Basic		
As reported	$ 3.38	$ 2.08
Pro forma	$ 3.38	$ 2.07
Diluted		
As reported	$ 3.37	$ 2.07
Pro forma	$ 3.37	$ 2.07

(d) Effective January 1, 2001, for U.S. GAAP reporting purposes, the Fund adopted SFAS 133, *"Accounting for Derivative Instruments and Hedging Activities"*. SFAS 133 establishes accounting and reporting standards requiring that all derivative instruments be recorded in the balance sheet as either an asset or a liability measured at fair value and requires that changes in fair value be recognized currently in income unless specific hedge accounting criteria are met.

With respect to its crude oil and natural gas contracts that do not qualify for hedge accounting treatment under SFAS 133, the Fund has recognized in earnings a gain of $4,733,000 ($3,095,000 net of tax) in 2003 compared to a loss of $25,312,000 ($14,529,000 net of tax) in 2002.

(e) U.S. GAAP requires the reporting of comprehensive income in addition to net earnings. The Fund's comprehensive income for the year ended December 31, 2003 includes an unrealized loss of $58,556,000 ($38,290,000 net of tax) on instruments qualifying for hedge accounting under SFAS 133. Comprehensive income for the year ended December 31, 2002 includes an unrealized gain of $18,145,000 ($10,415,000 net of tax). The effect on other comprehensive income of the Fund's financial instruments that qualify for hedge accounting, net of tax, are summarized below:

Net unrealized gain (loss) on hedging instruments	2003	2002
($ thousands)		
Interest rate swap	$ (40,642)	$ 21,295
Cross-currency swap	123	(1,148)
Natural gas swaps	2,121	(9,732)
Electricity swap	108	–
Gain (loss) on hedging instruments, net of tax	$ (38,290)	$ 10,415

(f) In June 2001, the FASB issued SFAS 143, *"Accounting for Asset Retirement Obligations"*. SFAS 143 requires liability recognition for retirement obligations associated with tangible long-lived assets. The obligations included within the scope of SFAS 143 are those for which the Fund faces an obligation for settlement and are to be measured initially at fair value. The liability is accreted through depletion, depreciation , amortization and accretion expense to account for the passing of time. The initial fair value of the obligation is to be capitalized as part of the cost of the related long-lived asset and amortized to expense over the useful life of the asset. SFAS 143 has been adopted, prospectively, as of January 1, 2003.

The Fund previously estimated costs of abandonment, removal, site reclamation and other similar activities in the total costs that are subject to depreciation, depletion and amortization. The accumulated amortization of these costs is represented as a liability on the balance sheet, net of actual costs, as accumulated site restoration. As a result of the application of SFAS 143, Enerplus has recorded an increase to net income of $29,023,000 (net of deferred income taxes of $13,305,000) representing the cumulative effect of adopting SFAS 143. Additionally, the Fund experienced an increase to its asset retirement obligation of $4,279,000, an increase to PP&E of $60,161,000 and an increase in accumulated depreciation, depletion and amortization of $13,554,000. Furthermore, deferred income taxes on the balance sheet have decreased by $13,350,000 as a result of the change in accounting principles.

Depreciation, depletion, amortization and accretion costs for U.S. GAAP include depletion of the capitalized abandonment costs in the amount of $2,797,000 and accretion of the asset retirement obligation in the amount of $4,115,000 for the year ended December 31, 2003. For Canadian GAAP the amortization of site restoration included in depletion, depreciation and amortization expense for the year ended December 31, 2003 was $7,993,000. The difference between Canadian and U.S. GAAP results in a $1,081,000 ($704,000 net of tax) reduction in depletion, depreciation, amortization and accretion for U.S. GAAP.

Following is a reconciliation of the asset retirement obligation from January 1, 2003 to December 31, 2003:

Asset retirement obligation ($ thousands)	2003
Accumulated site restoration as of January 1, 2003	$ 59,038
Cumulative effect of change in accounting principle to asset retirement obligation	4,279
Increase in retirement obligations	3,200
Retirement obligations settled	(6,696)
Accretion expense	4,115
Asset retirement obligation as of December 31, 2003	63,936

(g) The Fund denotes operating activities before changes in operating working capital on the Consolidated Statement of Cash Flows as funds flow from operations. This notation does not have any standardized meaning as prescribed by GAAP, and would not be presented under U.S. GAAP.

(h) Enerplus has adopted FASB Interpretation No. 45, *"Guarantor's Accounting and Disclosure Requirements for Guarantees"*, for the year ended December 31, 2003. The fair market value of the Fund's guarantees are considered to be nominal.

Disclosure of the Impact of Recently Issued Accounting Standards

In May 2003, the "FASB" issued Statement of Financial Accounting Standards No. 150 ("FAS 150"), *"Accounting for Certain Financial Instruments with Characteristics of Liabilities and Equity"*. In December 2003, the FASB issued Revised FASB Interpretation No. 46, *Consolidation of Variable Interest Entities*. These accounting standards are not expected to have a material impact on the Fund at this time. Enerplus will continue to monitor the relevance of all accounting standards and will measure the impact when they are determined to apply.

5 Year Detailed Statistical Review

The information contained in the table below reflects the reverse takeover of Enerplus by EnerMark Income Fund on June 21, 2001 as required by Canadian generally accepted accounting principles.

($ thousands, except per unit amount)	2003	2002	2001	2000	1999
Financial					
Oil and gas sales (net of hedging)	**$ 890,011**	$ 621,450	$ 639,379	$ 343,182	$ 169,541
Cash available for distribution	**$ 379,055**	$ 246,787	$ 316,454	$ 168,181	$ 78,189
Per unit	**$ 4.32**	$ 3.32	$ 5.67	$ 5.49	$ 3.70
Net income	**$ 249,600**	$ 115,876	$ 180,269	$ 82,150	$ 25,754
Per unit	**$ 2.90**	$ 1.61	$ 3.28	$ 3.06	$ 1.25
Total net capital expenditures	**$ 312,073**	$ 361,702	$ 874,420	$ 700,714	$ 17,837
Total assets	**$ 2,615,612**	$2,471,631	$ 2,284,253	$1,567,952	$ 576,901
Long-term debt, net of cash	**$ 257,701**	$ 361,011	$ 411,610	$ 275,098	$ 128,833
Net debt/funds flow ratio	**0.6x**	1.2x	1.2x	1.6x	1.6x

($ per BOE except percentage data)	2003	2002	2001	2000	1999
Average Benchmark pricing					
AECO natural gas (per Mcf)	**$ 6.70**	$ 4.07	$ 6.30	$ 5.02	$ 2.96
NYMEX natural gas (US$ per Mcf)	**5.44**	3.25	4.38	3.91	2.27
WTI crude oil (US$ per bbl)	**31.04**	26.08	25.97	30.19	19.24
CDN$/US$ exchange rate	**$ 0.7158**	$ 0.6369	$ 0.6458	$ 0.6736	$ 0.6733

($ per BOE except percentage data)	2003	2002	2001	2000	1999
Oil and Gas Economics					
Net royalty rate	**20%**	21%	23%	23%	19%
Weighted average price (pre-hedging)	**$ 36.94**	$ 27.49	$ 29.89	$ 30.94	$ 18.35
Hedging	**(1.81)**	(0.38)	2.54	(0.80)	(0.03)
Weighted average price (net of hedging)	**35.13**	27.11	32.43	30.14	18.32
Net royalty expense	**7.51**	5.75	6.73	7.10	3.47
Operating expense	**6.73**	5.86	6.09	4.83	4.02
Operating netback	**20.89**	15.50	19.61	18.21	10.83
General and administrative expense*	**0.95**	0.70	0.66	0.63	0.62
Management fee	**2.29**	0.94	0.47	0.40	0.24
Interest expense, net of interest and other income	**0.74**	0.78	0.85	1.30	0.87
Foreign exchange*	**0.08**	–	–	–	–
Capital taxes	**0.26**	0.23	0.24	0.26	0.17
Restoration and abandonment cash costs	**0.26**	0.20	0.13	0.13	0.12
Gain on sale of investment	–	–	–	–	0.06
Funds flow from operations	**$ 16.31**	$ 12.65	$ 17.26	$ 15.49	$ 8.75

*Does not include non-cash portion of expense

Combined Operational Statistics

The information contained in the table below reflects the combined results of Enerplus and EnerMark Income Fund for the years indicated as if the combination of the funds had been effective January 1, 1997. This information may not be representative of the actual results had the combination occurred on that date. No pro forma adjustments have been made to give effect to the combination of Enerplus and EnerMark Income Fund for these periods. The information in this table is different from the financial statements and MD&A which account for the combination as a reverse takeover of Enerplus by EnerMark Income Fund on June 21, 2001 as required by Canadian generally accepted accounting principles.

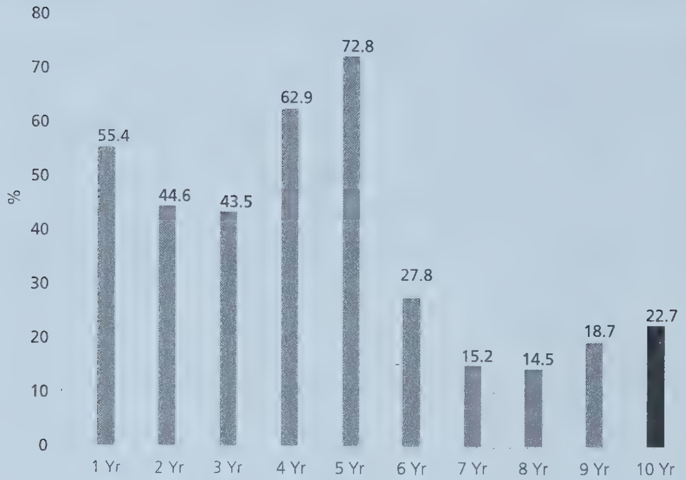
	2003[1]	2002	2001	2000	1999
Daily Production					
Crude oil per day (bbls/day)	**24,597**	23,288	24,010	18,118	16,938
NGLs per day (bbls/day)	**4,666**	4,410	4,650	3,395	3,153
Natural Gas per day (Mcf/day)	**240,907**	210,517	203,727	149,616	119,303
BOE per day	**69,414**	62,784	62,615	46,449	39,975
Proved Reserves					
Crude oil (Mbbls)	**91,063**	105,247	94,847	101,439	71,756
NGLs (Mbbls)	**13,571**	16,035	16,114	16,973	11,740
Natural Gas (MMcf)	**867,204**	1,001,913	951,133	954,124	550,275
MBOE	**249,168**	288,267	269,483	277,433	175,209
Risked Probable Reserves[2]					
Crude oil (Mbbls)	**27,807**	16,725	18,821	20,675	13,770
NGLs (Mbbls)	**3,742**	2,319	2,337	1,722	1,620
Natural Gas (MMcf)	**284,096**	138,789	130,345	131,818	265,638
MBOE	**78,898**	42,175	42,882	44,367	59,664
Proved plus Risked Probable Reserves					
Crude oil (Mbbls)	**118,870**	121,972	113,668	122,114	85,526
NGLs (Mbbls)	**17,313**	18,354	18,451	18,695	13,360
Natural Gas (MMcf)	**1,151,300**	1,140,702	1,081,478	1,085,942	815,913
MBOE	**328,066**	330,442	312,365	321,800	234,873
Reserve life index (years) BOE Combined[3]	**13.3**	13.8	14.0	13.7	13.5

[1] 2003 Reserve information reflects NI 51-101 reporting methodology. All prior years have not been restated for NI 51-101.

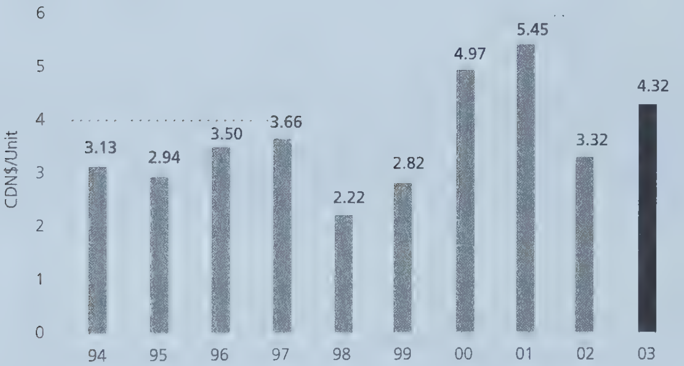
[2] Probable reserves for years 2002 and prior have been risked by 50%

[3] The Reserve Life Index (RLI) is based upon year end proved plus probable reserves (established reserves for years 2002 and prior) divided by following year production volumes determined in the independent reserve engineering report for 2003 and management's estimate for all prior years.

Ten Year Historical Performance



Total Return per Year



Cash Distributions per Year

Unit Trading Information

TSX 10 Year Trading Summary

ERF.un trading information on the Toronto Stock Exchange as at December 31,

CDN$	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
High	30.00	33.00	35.25	33.00	25.50	19.20	24.60	32.86	29.00	**40.72**
Low	22.20	21.60	28.50	20.40	12.00	12.60	15.60	22.00	22.85	**25.82**
Close	27.00	32.25	32.40	23.40	12.96	16.32	22.90	24.75	28.05	**39.35**
Volume (000)	4,245	9,898	16,160	12,672	8,230	7,322	10,214	29,466	37,492	**51,800**

NYSE 4 Year Trading Summary

Enerplus Resources Fund began trading on the New York Stock Exchange on November 17, 2000. ERF trading information on the New York Stock Exchange as at December 31,

US$	2000	2001	2002	2003
High	15.25	23.50	19.08	**31.20**
Low	14.69	13.79	14.30	**17.06**
Close	15.25	15.56	17.75	**30.44**
Volume (000)	121	19,740	31,350	**60,624**

Distribution Reinvestment Plan

Enerplus Resources Fund has a convenient method for Canadian residents to reinvest cash distributions or invest additional funds into new trust units. Unitholders who are residents of Canada are eligible to participate in the Plan. If your units are held for you by your broker, investment dealer or other financial intermediary, you must direct that company to enroll your units into the Plan.

To obtain more information and/or enrolment forms, please contact our Investor Relations Department at:
1-800–319–6462, in Calgary at (403) 298–2200, by fax at (403) 298–2211;
or by email at investorrelations@enerplus.com.

Income Tax – Canadian residents (CDN$ per Unit)

The following table outlines the breakdown of cash distributions per unit paid by Enerplus Resources Fund during the period February 10, 2003 up to and including January 10, 2004 for Canadian Income Tax purposes.

Record Date	Payment Date	Total Distribution Paid	Taxable Other Income	Taxable Dividend	Return of Capital Amt.
Feb 10, 2003	Feb 20, 2003	$ 0.320000	$ 0.257431	$ 0.006249	$ 0.056320
Mar 10, 2003	Mar 20, 2003	$ 0.350000	$ 0.282155	$ 0.006245	$ 0.061600
Apr 10, 2003	Apr 20, 2003	$ 0.349823	$ 0.282017	$ 0.006237	$ 0.061569
May 10, 2003	May 20, 2003	$ 0.370000	$ 0.298653	$ 0.006227	$ 0.065120
Jun 10, 2003	Jun 20, 2003	$ 0.370000	$ 0.298675	$ 0.006205	$ 0.065120
Jul 10, 2003	Jul 20, 2003	$ 0.370000	$ 0.298681	$ 0.006199	$ 0.065120
Aug 10, 2003	Aug 20, 2003	$ 0.370000	$ 0.299060	$ 0.005820	$ 0.065120
Sep 10, 2003	Sep 20, 2003	$ 0.370000	$ 0.299069	$ 0.005811	$ 0.065120
Oct 10, 2003	Oct 20, 2003	$ 0.370000	$ 0.299073	$ 0.005807	$ 0.065120
Nov 10, 2003	Nov 20, 2003	$ 0.350000	$ 0.282598	$ 0.005802	$ 0.061600
Dec 10, 2003	Dec 20, 2003	$ 0.350000	$ 0.282611	$ 0.005789	$ 0.061600
Dec 31, 2003	Jan 20, 2004	$ 0.350000	$ 0.282896	$ 0.005504	$ 0.061600
Total per Unit		**$ 4.289823**	**$ 3.462919**	**$ 0.071895**	**$ 0.755009**

Income Tax – United States residents (US$ per Unit)

The following table outlines the breakdown of cash dividends paid per Unit by Enerplus Resources Fund, prior to any amounts deducted for Canadian withholding tax, for Units held through a broker or other intermediary for the period January 20, 2003 to December 20, 2003 for U.S. income tax purposes. All amounts shown are in U.S. dollars as converted on the applicable payment date.

Record Date	Payment Date	Distribution Paid CDN$	Exchange Rate	Distribution Paid US$	Taxable Qualified Dividend US$	NonTaxable Return of Capital US$
Dec 31, 2002	Jan 20, 2003	$ 0.30	0.650407	$ 0.195122	$ 0.170794	$ 0.024328
Feb 10, 2003	Feb 20, 2003	$ 0.32	0.662954	$ 0.212145	$ 0.185695	$ 0.026450
Mar 10, 2003	Mar 20, 2003	$ 0.35	0.674082	$ 0.235929	$ 0.206513	$ 0.029416
Apr 10, 2003	Apr 20, 2003	$ 0.35	0.686908	$ 0.240418	$ 0.210443	$ 0.029975
May 10, 2003	May 20, 2003	$ 0.37	0.738280	$ 0.273164	$ 0.239106	$ 0.034058
Jun 10, 2003	Jun 20, 2003	$ 0.37	0.740631	$ 0.274033	$ 0.239867	$ 0.034166
Jul 10, 2003	Jul 20, 2003	$ 0.37	0.708315	$ 0.262077	$ 0.229401	$ 0.032676
Aug 10, 2003	Aug 20, 2003	$ 0.37	0.711946	$ 0.263420	$ 0.230577	$ 0.032843
Sep 10, 2003	Sep 20, 2003	$ 0.37	0.741510	$ 0.274359	$ 0.240152	$ 0.034207
Oct 10, 2003	Oct 20, 2003	$ 0.37	0.757289	$ 0.280197	$ 0.245262	$ 0.034935
Nov 10, 2003	Nov 20, 2003	$ 0.35	0.765872	$ 0.268055	$ 0.234634	$ 0.033421
Dec 10, 2003	Dec 20, 2003	$ 0.35	0.748503	$ 0.261976	$ 0.229313	$ 0.032663
Total per Unit		**$ 4.24**		**$ 3.040895**	**$ 2.661757**	**$ 0.379138**

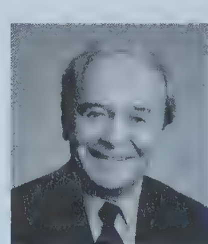
Directors

Douglas R. Martin[1][2][10]
President
Charles Avenue Capital Corp.
Calgary, Alberta

André Bineau[3][5]
Vice President of Investements
Association de bienfaisance et de retraite des policièrs et policires de la Ville de Montréal
Montréal, Québec

Derek J. M. Fortune[3][9]
Chairman
DF Consulting & Financial Services Inc.
Ottawa, Ontario

Gordon J. Kerr
President & Chief Executive Officer
EnerMark Inc.
Calgary, Alberta



Robert L. Normand[6][9]
Corporate Director
Rosemère, Quebéc

Eric P. Tremblay
Senior Vice President Capital Markets
EnerMark Inc.
Calgary, Alberta

Donald West[7]
Retired Executive
Calgary, Alberta

Harry B. Wheeler[5][8]
President
Colchester Investments Ltd.
Calgary, Alberta

Robert L. Zorich[4]
Managing Director
EnCap Investments L.P.
Houston, Texas

(1) Chairman of the Board
(2) *Ex-Officio* member of all Committees of the Board
(3) Member of Corporate Governance Nominating and Environment, Health & Safety Committee
(4) Chairman of the Corporate Governance, Nominating and Environment, Health & Safety Committee
(5) Member of the Audit & Risk Management Committee
(6) Chairman of the Audit & Risk Management Committee
(7) Member of the Reserves Committee
(8) Chairman of the Reserves Committee
(9) Member of Compensation and Human Resources Committee
(10) Chairman of the Compensation and Human Resources Committee

Officers

Gordon J. Kerr
President & Chief Executive Officer

Heather J. Culbert
Seniore Vice President, Corporate Services

Garry A. Tanner
Senior Vice President & Chief Operating Officer

Eric P. Tremblay
Senior Vice President, Capital Markets

Robert J. Waters
Senior Vice President & Chief Financial Officer

Jo-Anne M. Caza
Vice President, Investor Relations

Daryl W. Cook
Vice President, Operations

Ian C. Dundas
Vice President & Director, Business Development

Wayne T. Foch
Vice President, Finance

David A. McCoy
General Counsel & Corporate Secretary

Daniel M. Stevens
Vice President, Development Services

Rodney D. Gray
Controller, Finance

Wayne T. Ford
Controller, Operations

Christina Meeuwsen
Assistant Corporate Secretary

Corporate Information

Operating Companies Owned by Enerplus Resources Fund
EnerMark Inc.
Enerplus Resources Corporation

Legal Counsel
Blake, Cassels & Graydon LLP
Calgary, Alberta and Toronto, Ontario

Auditors
Deloitte & Touche LLP
Calgary, Alberta

Transfer Agent
The CIBC Mellon Trust Company
Calgary, Alberta
Toll free: 1.800.387.0825
Email: inquiries@cibcmellon.com

Co–Transfer Agent
Mellon Investor Services L.L.C.
Ridgefield, New Jersey

Independent Reserve Engineers
Sproule Associates Limited
Calgary, Alberta

Stock Exchange Listings and Trading Symbols
New York Stock Exchange: ERF
Toronto Stock Exhange: ERF.un

Head Office
The Dome Tower
3000, 333 – 7th Avenue S.W.
Calgary, Alberta T2P 2Z1

Telephone: 403.298.2200
Toll free: 1.800.319.6462
Fax: 403.298.2211
Email: investorrelations@enerplus.com

For more information, visit our website: www.enerplus.com

Enerplus Internet Site

Enerplus Resources Fund has a comprehensive website that provides investors with an immediate source of all public information. The following documents are available at www.enerplus.com:

- Unit Trading Information
- Annual and Quarterly Reports
- Tax Information
- News Releases
- Recent Presentations
- 15 Minute Delayed Stock Quote
- Historical Distribution Tables
- Distribution Reinvestment and Unit Purchase Plan Information
- Adjusted Cost Base Calculator
- Important Dates and Events

Annual General Meeting

Unitholders are encouraged to attend the Annual General Meeting being held on:

Friday, May 7, 2004,
10:00 a.m., local time at
The Metropolitan Centre,
333 – 4th Avenue SW
Calgary, Alberta

Those unable to attend are asked to sign and return the Form of Proxy with this annual report.

Abbreviations

AECO	Alberta Energy Company interconnect with the Nova Gas System
ARTC	Alberta Royalty Tax Credit
bbl(s)/day	barrel(s) per day
BOE(s)/day	barrel of oil equivalent per day (6 Mcf gas = 1 bbl crude oil)
COGPE	Canadian oil and gas property expense
CAPP	Canadian Association of Petroleum Producers
Established Reserves	proved and half probable reserves
FD&A Costs	finding, development and acquisition costs
FVUP	full value unit plan
IP Rate	initial production rate
Mbbls	thousand barrels
MBOE	thousand barrels of oil equivalent
Mcf/day	thousand cubic feet per day
MMbbl(s)	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British thermal units
MMcf/day	million cubic feet per day
NGC	natural gas from coal
NI 51–101	National Instrument 51–101 (pertaining to reserve reporting)
NYSE	New York Stock Exchange
P+P Reserves	proven and risked probable resesrves
PDP Reserves	proved developed producing reserves
SAGD	steam assisted gravity drainage
TSX	Toronto Stock Exchange
W.I.	percentage working interest of ownership
WTI	West Texas Intermediate oil at Cushing, Oklahoma

Gordon J. Kerr
President & Chief Executive Officer

Our focus is on creating value consistently over the long-term for our unitholders

enerPLUS
RESOURCES FUND